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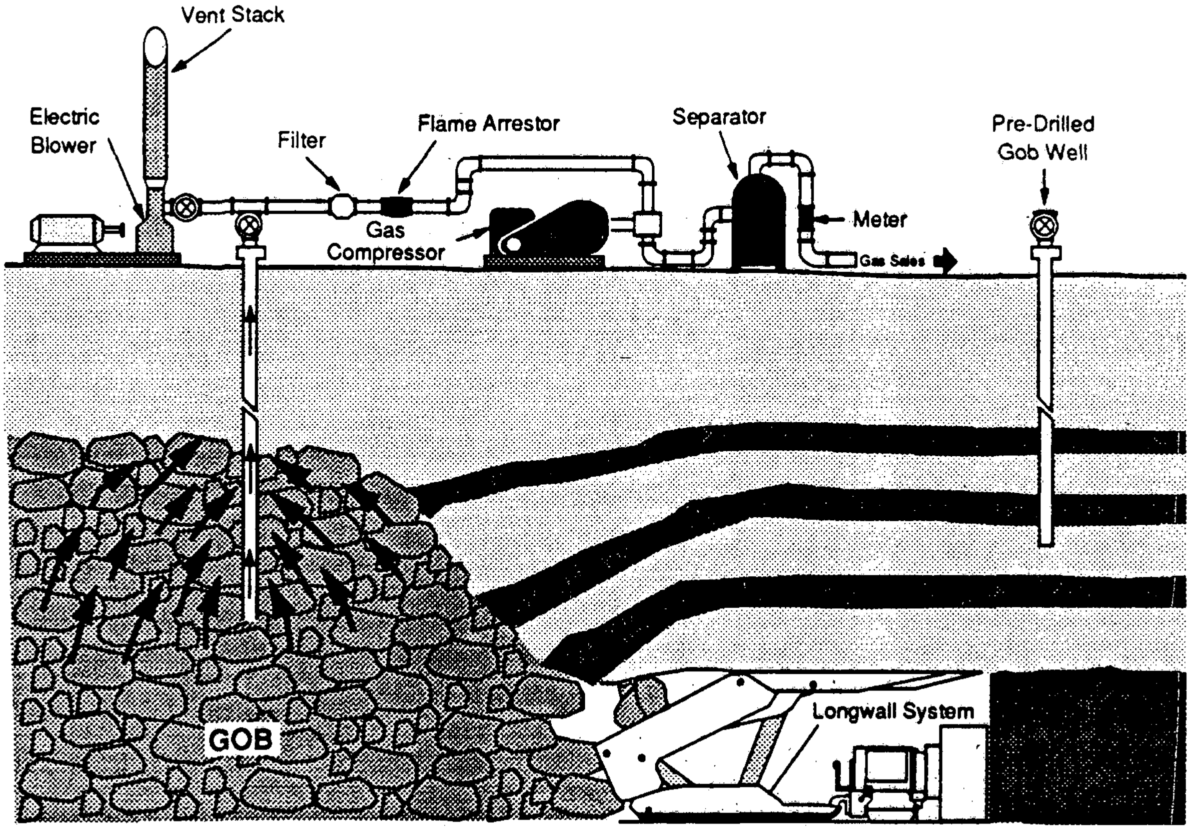
Methane Emissions From Coal Mining

Issues And Opportunities For Reduction



Methane Emissions From Coal Mining: Issues and Opportunities for Reduction

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OVERVIEW AND INTRODUCTION

In recent years, methane (CH_4) has been identified as a potent greenhouse gas with a radiative forcing potential of 30 to 55 times that of carbon dioxide per kilogram emitted.[1] Total annual methane emissions from all sources are estimated to be about 540 (±95) teragrams and anthropogenic sources account for 65 to 70 percent of total emissions.[2,3] It has been documented that atmospheric concentrations of methane have more than doubled over the last two centuries and are continuing to increase on the order of 1 percent annually, or about 0.017 ppmv (parts per million by volume) per year.

Increasing atmospheric concentrations of methane will have important implications for global climate and perhaps for the stratospheric ozone layer and background levels of tropospheric ozone. Thus, the U.S. Environmental Protection Agency has initiated a series of studies to more completely understand the various sources of emissions, to develop methodologies for estimating emissions from these sources, and to explore the technologies and economics of reducing methane emissions. Based on these studies, strategies for stabilizing and further reducing methane emissions will be developed.

Coal mining, particularly from underground mines, contributes to the increasing abundance of atmospheric methane, accounting for 7 to 12 percent of annual methane emissions (33 to 64 million metric tons in 1987). Coal production has been increasing steadily in the last 30 years and in 1987 world coal production reached 4.6 billion metric tons. With world energy demand still growing, coal production levels are expected to continue to increase in the future. Thus, methane emissions from this source could increase significantly, perhaps reaching 72 to 81 million metric tons by the year 2000 if options for reducing emissions are not pursued.

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[1] The ratio of carbon dioxide to methane depends on how long into the future the radiative effects are compared since methane has a much shorter lifetime in the atmosphere than CO_2. These ratios represent the relative effects over the next 50 to 100 years.

[2] One million metric tons (10^{12} grams or 1 teragram) is equal to 1.49 billion cubic meters (52.6 billion cubic feet).

[3] R.S. Cicerone and R.S. Oremland, 1988.

Methane is generated during the process of coal formation and is subsequently stored in the coal seams and surrounding rock strata. Methane is contained in the coal and other strata by pressure, and when pressure decreases (either naturally through uplift and erosion or as a result of mining activities) methane flows out of the coal and into the atmosphere. Methane released as a result of underground mining activities flows first into the mine workings, where it is a safety hazard because it is explosive in low concentrations in air. As a result, underground mines are ventilated with large quantities of air to remove the methane and vent it to the atmosphere.

A number of technologies have been developed to degasify coal seams and reduce methane emissions into mine workings. To a large extent, these technologies have been used for purposes of mine safety and to reduce the operating costs of the mines. For the most part, methane recovered using these technologies is currently vented to the atmosphere. However, more of this methane could be recovered and utilized without compromising mine safety.

Reducing methane emissions from coal mining by recovering and using this liberated gas could play a key role in stabilizing the atmospheric methane concentrations at approximately present levels. Currently, opportunities to recover methane from coal mining are limited by a variety of technical, legal, regulatory, institutional and other barriers. These barriers must be identified and removed if the recovery of methane liberated during coal mining is to be widely pursued.

Key Findings

This report estimates global methane emissions from coal mining on a country-specific basis, evaluates the technologies available to degasify coal seams, and assesses the economics of recovering methane liberated during mining. The draft findings of this report were presented at the "International Workshop on Methane Emissions from Natural Gas Systems, Coal Mining and Waste Management Systems," which was held in Washington, D.C., on April 9 to 13, 1990. These findings were discussed during the workshop and revised based on the comments received during the discussions. The findings of the workshop regarding methane emissions from coal mining and a list of the workshop attendees for this session are included in Appendices A and B of this report.

The report's main findings are presented below. Based on this analysis and the consensus of the recent international workshop, it appears that there are promising opportunities for reducing methane emissions from coal mining. Some of these opportunities have been demonstrated, and others remain to be assessed and demonstrated in the field. Undertaking the necessary technical assessments and demonstrations is a recognized priority.

Emission Estimates

- The study estimates that 33 to 64 million metric tons of methane were liberated in 1987 as a result of coal mining, processing and utilization. More than 90 percent of these emissions were associated with coal mining activities in the top ten coal producing nations, and almost 75 percent were associated with coal production in only four countries (China, the Soviet Union, Poland, and the United States).

- Methane emissions associated with coal mining are likely to increase in the future and could reach 72 to 81 million metric tons by the year 2000. These increases will be driven by increased world coal production and by the expected shift in many countries toward deeper underground coal mines as more accessible, shallower coal seams are exhausted.

- The estimates contained herein are based on numerous assumptions and should be considered preliminary and approximate. In this study, methane emissions were divided between those from surface and underground mines, which represent a major source of variation in emission levels. Other sources of uncertainty and variation remain, however, including the relationship between in-situ methane content in the coal and methane emissions during mining and the extrapolation of U.S. estimates to other countries. A range of $\pm$23 percent was assumed for U.S. methane emissions from coal mining to account for the uncertainties associated with estimating mining emissions based on the methane content of the mined coal. An additional uncertainty of ±10 percent was assumed in estimating international methane emissions based on U.S. data.

Methane Recovery and Utilization

- Methane is explosive in concentrations of 5 to 15 percent in air, and as a result, control of methane has long been essential in underground coal mines for safety reasons. Over the years, a number of techniques have been developed to degasify coal seams and supplement conventional underground mine ventilation systems. Many of these techniques are used in underground mines in the United States and other countries.

- In many cases, the methane recovered using these degasification techniques is currently vented to the atmosphere. This methane could be used in a variety of ways, including on-site power generation, chemical feedstocks, and sale to natural gas pipelines.

- Although the economics of methane recovery must be assessed on a site-specific basis, preliminary economic analyses indicate that under certain conditions methane recovery is economically attractive. Key factors affecting the economics of methane recovery are: 1) the quantity of methane produced (specific to the unique properties of the coal); 2) the quality of the recovered methane; 3) the capital and operating costs of degasification technologies; 4) the selling price of the recovered methane (if injected into natural gas pipelines or utilized for other purposes); and 5) whether the environmental benefits of reducing methane emissions are incorporated into the economic analysis.

- Opportunities to recover methane prior to or in conjunction with coal mining are also affected by a variety of other factors, some of which include: 1) the legal ownership of the coalbed methane; 2) mining regulation constraints; and 3) establishing project economic viability. Exploring these factors is beyond the scope of this report. Additional efforts must focus on identifying and removing these and other barriers if the recovery of methane liberated during coal mining is to be widely pursued.

Report Organization

This report presents estimated methane emissions from coal mining and summarizes the issues associated with recovering and utilizing this methane. It is organized into four chapters as follows:

Chapter I	Methane Generation, Storage, and Flow in Coal
Chapter II	Methane Emissions During Coal Mining
Chapter III	Methane Emissions Estimate for Global Coal Mining
Chapter IV	Technical and Economic Evaluation of Methane Control Techniques

CHAPTER I

Methane Generation, Storage, and Flow in Coal

The process of coal formation, commonly called coalification, inherently generates methane and other byproducts. The formation of coal is a complex physio-chemical process occurring over a period of millions of years. The degree of coalification (coal rank) determines the quantity of methane generated and, once generated, the amount of methane stored in coal is controlled by the pressure and temperature of the coal seam and other, less defined characteristics of the coal.

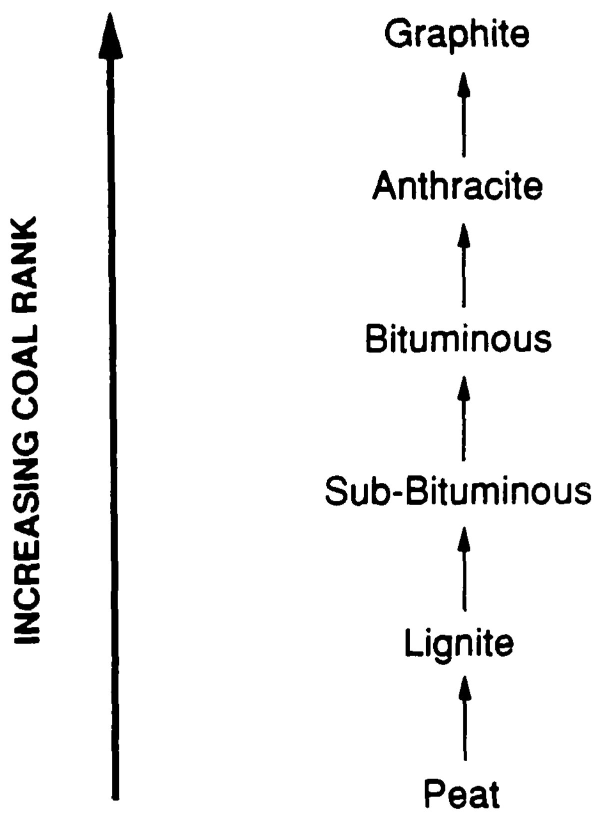
The methane will remain stored in the coal until the pressure on the coal is reduced, which can occur through the erosion of overlying strata or because of coal mining. Once the methane has been released, it flows through the coal toward a pressure sink (such as a coal mine) and into the atmosphere.

Coal Formation

Coal is a heterogeneous, carbon-rich (>50% by weight) material that is formed by the biochemical and geochemical alteration of peat, an organic material that is the source of most of the world's coal deposits. During the progressive transformation of peat into coal, discrete coal stages (or coal ranks) are attained that are dependent upon specific physio-chemical conditions, such as 1) heat flow, 2) pressure, 3) hydrogen ion concentration (pH), and 4) oxidation-reduction (redox) potential. This progressive transformation of organic matter begins with peat and ends with graphite (or pure carbon), as shown in Exhibit 1-1.

EXHIBIT 1-1

STAGES IN THE COALIFICATION PROCESS



Prepared by: ICF Resources, 1990.

The coalification process is divided into two stages, an early biochemical stage and a later a geochemical stage.[4] Biochemical coalification begins with the deposition of the peat and continues through the lignite and sub-bituminous coal ranks. In this first stage, the easily degradable compounds such as protoplasm, chlorophyll, and cellulose are converted to carbon dioxide, water, methane, and ammonia by the action of aerobic and anaerobic bacteria. The gaseous products formed during this stage are emitted to the atmosphere if the peat is not

[4] Stach, E., 1975; Van Krevelen, D.W., 1961.

deeply buried, move into overlying sediments if the peat is not capped by an impermeable layer, or remain in the peat. These biochemical processes occur at low temperatures, less than 50°C, and require reducing and acidic conditions.

As the altered peat undergoes further burial, increases in temperature and pressure initiate more complex chemical reactions in the remaining organic material. This is the geochemical stage of coalification, and it occurs above 50°C. With increasing geochemical alteration, the hydrogen and oxygen content of the organic material decreases, forming volatile by-products such as carbon dioxide, water, and methane. This causes a corresponding increase in the carbon content of the coal and in increased aromatization of the remaining organic compounds. The chemical components of coals of different rank are shown in Exhibit 1-2.

Of the two forces that cause geochemical coalification--heat and pressure--heat is the primary agent. In most cases, the heat source for coalification is supplied by the earth's geothermal energy, which increases with depth of burial. The geothermal gradient varies from 10°C/km to 50°C/km and averages about 30°C/km.[5] During the geologic past, high rank coal seams may have been covered by 10 kilometers or more of overlying strata, resulting in a burial temperature of over 300°C.

Although less important than heat, pressure also affects geochemical coalification, often controlling the temperature at which a specific chemical reaction can take place. As with temperature, pressure also increases with depth of burial. The average lithostatic gradient of 22.6 kPa/m and the average hydrostatic gradient of 9.79 kPa/m provide a first order estimate for relating depth to burial pressure.

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[5] Mason, B., 1966.

EXHIBIT 1-2

APPROXIMATE VALUES OF SOME COAL PROPERTIES IN DIFFERENT RANK RANGES

	Lignite	Subbituminous	Bituminous			Anthracite
			High Volatile	Medium Volatile	Low Volatile	
% C	65-72	72-76	76-87	89	90	93
% H	4.5	5.0	5.5	4.5	3.5	2.5
% O	30	18	4.13	3-4	3.0	2.0
Aromatic C Atoms[1] (% of total C)	50	65	N/A[2]	80-85	85-90	90-95
Benzene rings/layer	1-2	N/A	2-3	2-3	5	>25
Volatile matter[3], %	40-50	35-50	31-45	31-20	20-10	<10

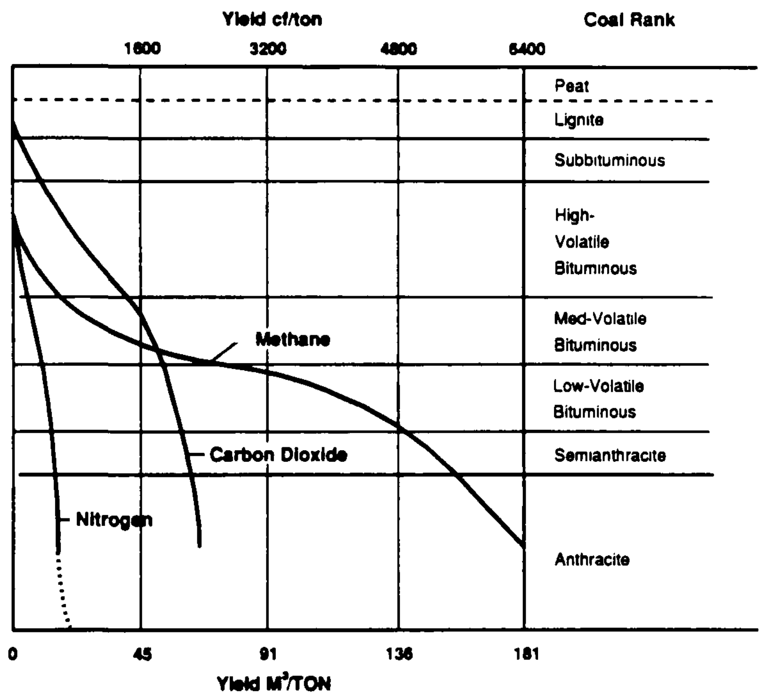
[1] Those carbon molecules that are bonded together by ringed structures.
[2] Not Available
[3] Those substances, other than moisture, that are given off as gas and vapor during combustion.

Source: Crelling, J.C, and Dutcher, R.R., 1988.

The volatile by-products--primarily carbon dioxide, water, methane and nitrogen--are generated during biochemical and geochemical coalification. As shown in Exhibit 1-3, methane generation increases dramatically as the coal approaches the low volatile bituminous rank.

EXHIBIT 1-3

GAS QUANTITIES GENERATED DURING COALIFICATION



Source: Hunt, J.M., 1979.

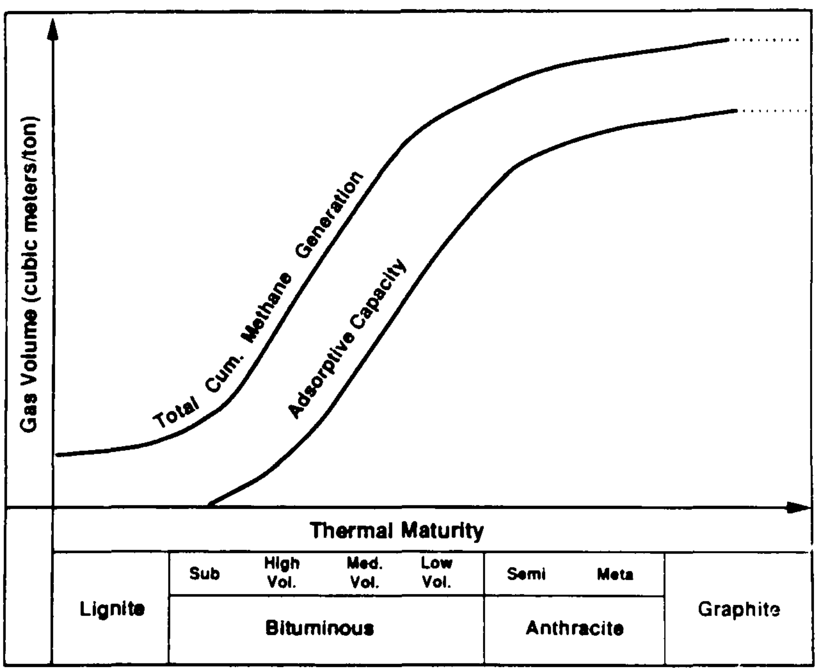
Methane Generation and Storage

Methane in coal is primarily stored as a monomolecular layer adsorbed onto the internal coal surface. Significant quantities of methane can be adsorbed in this fashion since the molecules are tightly packed in the monomolecular layer and because coal has a very large internal surface area. Pressure (and to a lesser degree temperature) controls the absolute quantity of methane adsorbed on coal. As pressure increases (and/or temperature decreases), more methane can be adsorbed in the coal.

As coal rank increases, the methane adsorptive capacity of the coal increases, but not as quickly as the total amount of methane generated, as shown in Exhibit 1-4. Therefore, the amount of methane (and other gasses) produced during coalification generally exceeds the retention capacity of the coal, and the excess methane often migrates into the surrounding strata.

EXHIBIT 1-4

METHANE GENERATION AND ADSORPTIVE CAPACITY



Source: Decker, A.D., 1989.

While over 180 cubic meters of methane per metric ton of coal can be generated as coal progresses from peat to anthracite, the quantity of methane retained in exhumed coal is substantially less. For example, the highest gas content measured for anthracite coal in the United States is 21.6 cubic meters per metric ton, only 12 percent of the total theoretical amount of methane generated during coalification.[6] This is because 1) the quantity of methane generated by coal generally exceeds the coal's adsorptive capacity and more importantly, 2) the pressure holding the methane in coal is much less today than when the methane was generated.

Because pressure increases with depth, deeper coal seams will generally hold larger quantities of methane than shallow coal seams of similar rank, as shown in Exhibit 1-5. In addition, as the coal rank increases, the quantity of adsorbed methane also increases. This relationship has been documented for coals throughout the world by numerous authors.[7] The methane content versus depth relationship is important for assessing future methane emissions from coal mines. Since much of the shallow, high quality coal has been mined (especially in the major non-United States coal producing countries), future coal mines will have to exploit deeper coal reserves which will lead to increased methane emissions to the atmosphere.

Methane Flow

The flow of methane through coal seams differs from the gas flow mechanisms of conventional reservoirs. As shown in Exhibit 1-6, methane transport in coal has three distinct properties: desorption from the coal surfaces, diffusion through the coal matrix, and flow through the coal seam fracture system.

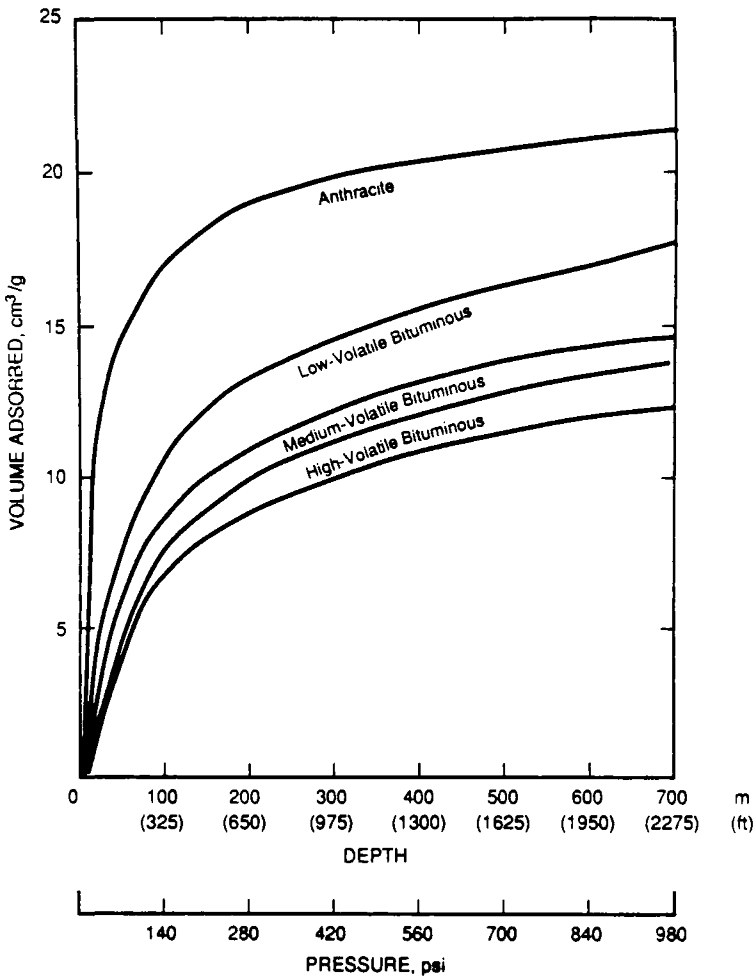
As mentioned previously, methane is stored in coal through the adsorption of methane molecules on the coal's internal surface area. When pressure on the coal seam is lowered, either

[6] Diamond, W.P., LaScola, J.C., and Hyman, D.M., 1986.

[7] See, for example: Eddy, G.E., Rightmire, C.T., and Byrer, C.W., 1982; Kelafant, J.R. and Boyer, C.M., 1988; Kelso, B.S., Wicks, D.E., and Kuuskraa, V.A., 1988; Johnston, D.P. and White, M.G.J., 1988; Shenyang Municipal Gas Corporation, 1989; and Basic, A. and Vukic, M., 1989.

EXHIBIT 1-5

RELATIONSHIP BETWEEN ADSORBED METHANE VOLUMES AND DEPTH AND PRESSURE FOR DIFFERENT COAL RANKS



Source: Kim, A.G., 1977.

through mining activities or through natural erosion, this methane is released (or begins to "desorb") and flows through the coal matrix.[8] After desorbing from the coal surface, the movement of methane through the coal is controlled by the concentration gradient of methane

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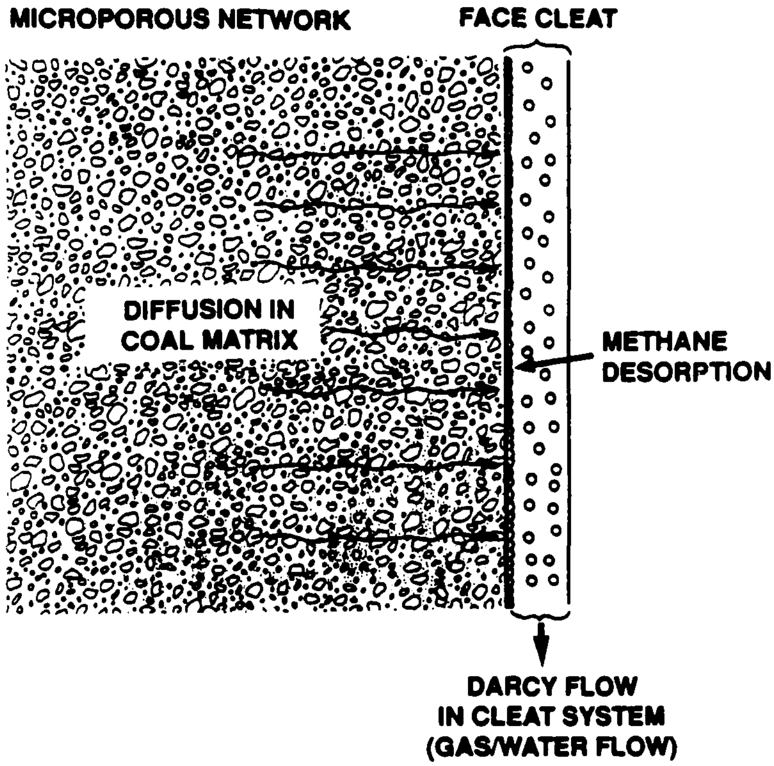
[8] For more information on methane flow in coal, see McElhiney, J.E., Koenig, R.A., and Schraufnagel, R.A., 1989.

EXHIBIT 1-6

THE TRANSPORT OF METHANE GAS IN COAL



Prepared by: ICF Resources, 1990.

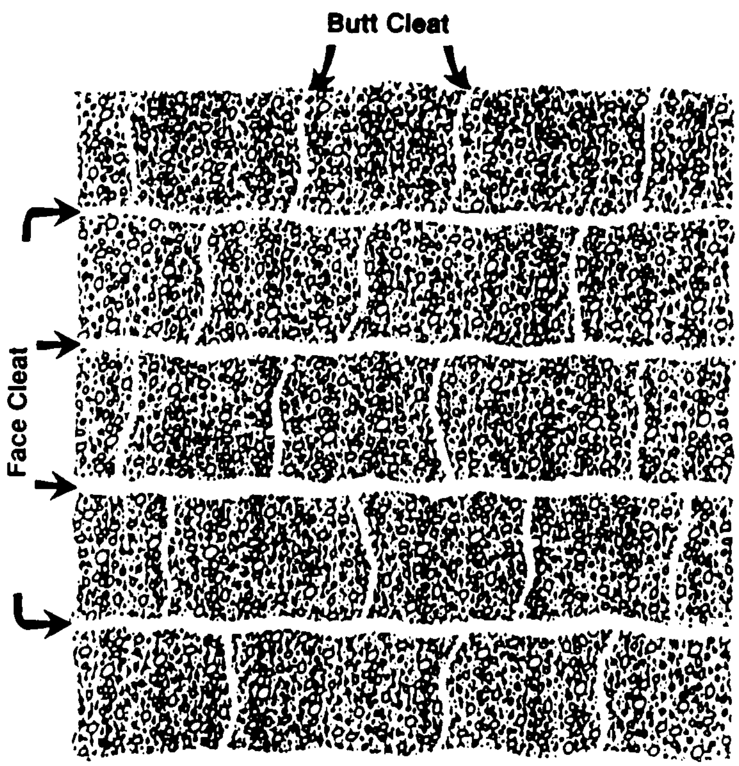
molecules (diffusion). In diffusion, molecules move from a zone of higher concentration to a zone of lower concentration. The movement of methane by diffusion occurs until the molecule intersects an open pathway or fracture in the coal.

Coal commonly has an extensive natural fracture system--referred to by the miner's term "cleat"--that is formed during coalification. The cleat system consists of two perpendicular sets of fractures. The more pronounced set of fractures is called the "face cleat," while the less pronounced fracture set is called the "butt cleat." The face cleat system is generally continuous, whereas butt cleats often terminate at intersections with face cleats. Cleat spacing can vary from millimeters to tens of centimeters, and appears to be related to coal rank and composition.[9] Typically, cleat systems become progressively better developed as coal rank increases. A schematic illustration of the coal cleat system is shown on Exhibit 1-7.

The size, spacing, and continuity of the cleat system control the flow of methane once it has diffused through the coal. Flow in the cleat system is described by D'Arcy's dynamic flow equations, with free gas moving as a result of a pressure gradient. A summary of this two-step process of methane flow in coal is shown in Exhibit 1-6.

EXHIBIT 1-7

SCHEMATIC ILLUSTRATION OF THE COAL CLEAT SYSTEM (PLAN VIEW)



Prepared by: ICF Resources, 1990.

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[9] Stach, E., 1975.

Each coal has a characteristic "sorption time" that includes the time required for methane molecules to desorb off of the coal surface and diffuse through the coal into the cleat system. A coal's sorption time can vary from less than one to over 300 days, depending on coal composition, rank, and cleat spacing. The rate at which methane desorbs and diffuses determines the stage in the coal mining and utilization process at which the methane is emitted. A coal with a short sorption time of one or two days, for example will emit most of its methane during mining operations, while a coal with a long sorption time of 100-200 days will emit much of its methane during post-mining coal processing.

Measuring the Methane Content of Coal

Various techniques have been developed to measure the methane content of coal. The Direct Method, initially developed in France, has been standardized by the U.S. Bureau of Mines (USBM) for measuring the quantity of methane in coal seams.[10] The measurements are performed on coal samples that have been recovered from mine workings or from wells drilled into the coal seam. The coal sample is collected and placed in a sealed canister, and the quantity of methane released is measured over time. When the coal sample ceases to emit measurable quantities of methane, the sample is crushed to release the remaining methane. This method can take anywhere from less than 1 to over 12 months, depending on the sorption time of the coal. The total methane content of the coal sample is then obtained from three components:

- **Lost Gas**: the quantity of methane estimated to have been lost during the recovery of the coal samples, prior to sealing the coal in the canister.

- **Desorbed Gas**: the quantity of methane desorbed from the coal sample while it is sealed in the canister.

[10] For information on the French development of the Direct Method, see Bertard, C., Bruyet, B. and Gunther J., 1970. For information on USBM work on the method, see Diamond, W.P. and Levine, J.R., 1981; or Kissell, F.N., McCulloch, C.M., and Elder, C.H., 1973.

- **Residual Gas**: the quantity of methane emitted after grinding the coal sample to a fine particle size.

The total quantity of methane obtained from these three components is compared to the mass of the sample, with the resulting methane content reported as a volume of methane per mass of coal, usually cubic centimeters per gram, cubic meters per metric ton, or cubic feet per standard ton.[11]

The USBM methodology has been slightly modified by other researchers, but its basic principles still hold as the industry standard.[12] The modifications included standardizing the volume of methane desorbed to standard pressure and temperature conditions (STP) and accounting for differences in sample collection methods, especially those relating to deep core wells or natural gas wells.

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[11] These units are related as follows:
1 cubic centimeter per gram = 1 cubic meter per metric ton = 32.04 cubic feet per standard ton
Note that there are 35.31 cubic feet in a cubic meter at STP and 1.1 standard tons in a metric ton.

[12] Kissell, F.N., 1981.

CHAPTER II

METHANE EMISSIONS DURING COAL MINING

The methane in coal remains adsorbed until pressure on the coal is lowered, which causes the release and flow of methane. The development of a coal mine inevitably leads to pressure reduction and causes methane to flow into the mine workings and then to the atmosphere. This chapter describes the relationship between various mining methods and methane emissions during mining. It then discusses the methane control measures currently practiced in the coal mining industry and the effect of post-mining processing and utilization of the coal on methane emissions.

Methane Emissions During Coal Mining

During coal mining, methane is emitted from the coal seam being mined and, in varying degrees, from the methane-charged coal seams and rock strata that lie above and below the mined seam. Most coal-bearing strata throughout the world contain a number of thin, unmineable seams that are associated with the main seam, as shown in Exhibit 2-1. The amount of methane released by mining activities thus depends on the methane content of the coal and its surrounding strata. In general, larger methane emissions are associated with underground mining than with surface mining because the deeper coals are under greater pressure and can hold more methane.

Underground Mining

Underground mining accounted for about 40 percent of total United States coal production in 1987 and about 45 percent of world-wide coal production.[13] Underground mining

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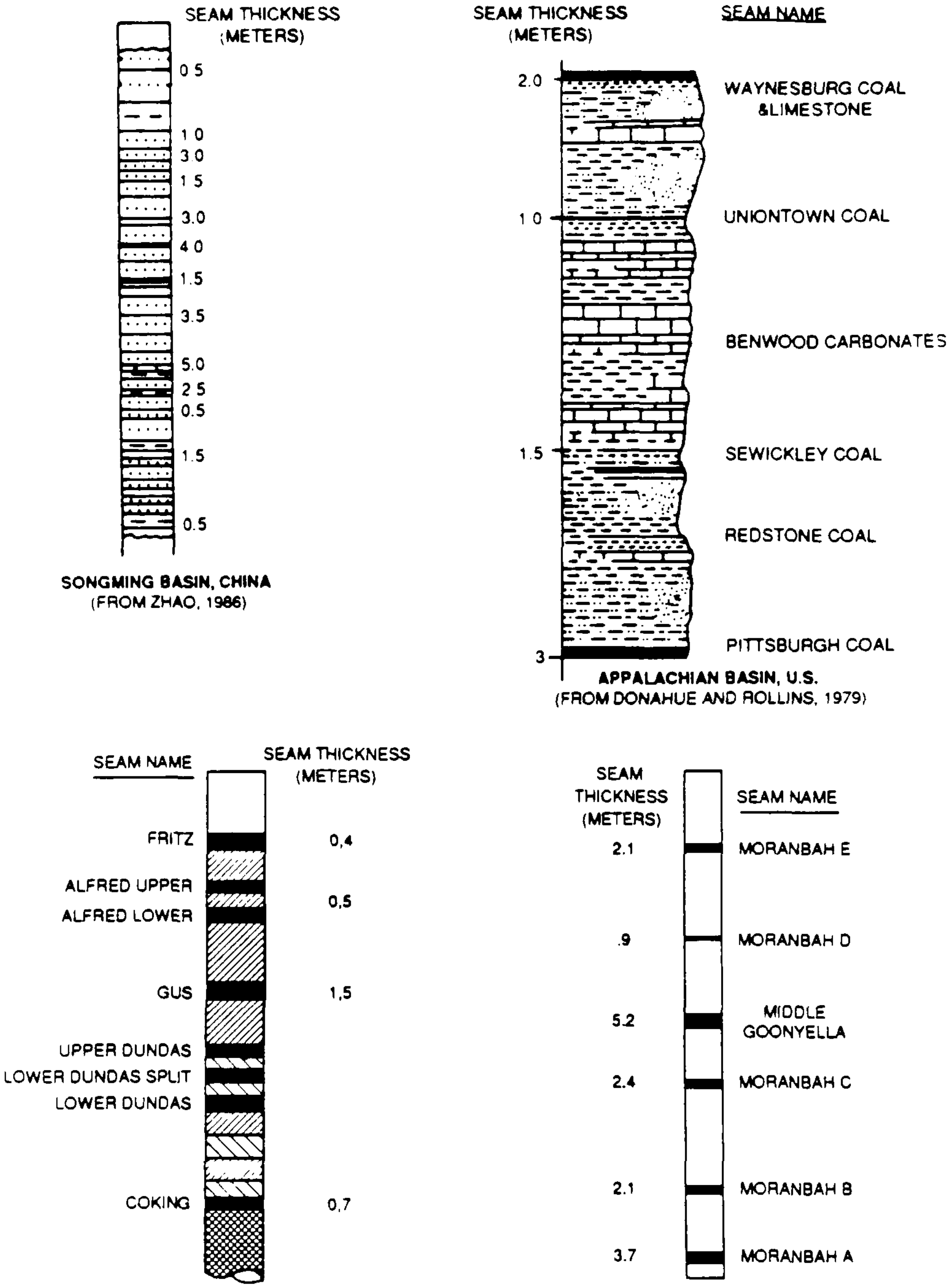
[13] EIA Coal Production, 1987; EIA Coal Information, 1987.

EXHIBIT 2-1

REPRESENTATIVE STRATIGRAPHIC COLUMNS FOR FOUR COAL BASINS OF THE WORLD



SONGMING BASIN, CHINA
(FROM ZHAO, 1986)

APPALACHIAN BASIN, U.S.
(FROM DONAHUE AND ROLLINS, 1979)

VRYHEID COALFIELD, SOUTH AFRICA
(FROM COMM OF INQ INTO THE COAL RESOURCES, S.A.)

BOWEN COAL BASIN, AUSTRALIA
(FROM JOHNSON AND WHITE, 1988)

Prepared by: ICF Resources, 1990.

is typically pursued when coal seams are buried at depths greater than 60 meters. Two underground mining methods are commonly used--room and pillar mining and longwall mining--and these methods can result in different methane emissions levels.[14]

During underground mining, methane emissions begin with the development of the mine works, including the construction of shafts and tunnels to access the buried coal seam. Mine entries can be vertical or inclined depending on the depth of the coal seam. Inclined slopes are typically used only if the seam is less than 300 meters deep, while vertical shafts can be used at any depth. Whether inclined or vertical, however, these entries are used to transport personnel and equipment and also serve as pathways for ventilation air, which is circulated throughout the mine in order to dilute and remove the emitted methane.

Room and Pillar Mines. Room and pillar mining is the most common underground mining method used in the United States. In this method, two or more sets of entries are driven into the coalbed from the base of the entrance shaft. About every 100 meters, side entries are driven from the main entries at 45 to 90 degree angles. From these latter entries, rooms 5 to 6 meters wide and about 15 meters apart are created by extracting the coal. The block of coal left in between the rooms is called a pillar, and it supports the mine roof. Exhibit 2-2 shows the sequential development of a room and pillar mine. The coal is extracted using either mechanical mining machines (continuous miners) or by blasting and loading.

In the room and pillar method, 30 to 60 percent of the coal remains in the pillars after the rooms are mined. Once the mining operation has extended the entries to their maximum length and all of the coal has been removed from the rooms, the pillars may then be removed. The pillars farthest from the mine opening are removed first and those nearest the shaft or slope are removed last. To mine the pillars, temporary supports are built (usually constructed of timber) and the pillar of coal is either partially or entirely removed. The extent of pillar removal depends on many factors, including the integrity of the mine roof, the strength of the coal, and the geometry of the pillars. In some cases, the pillars may be completely extracted safely, causing

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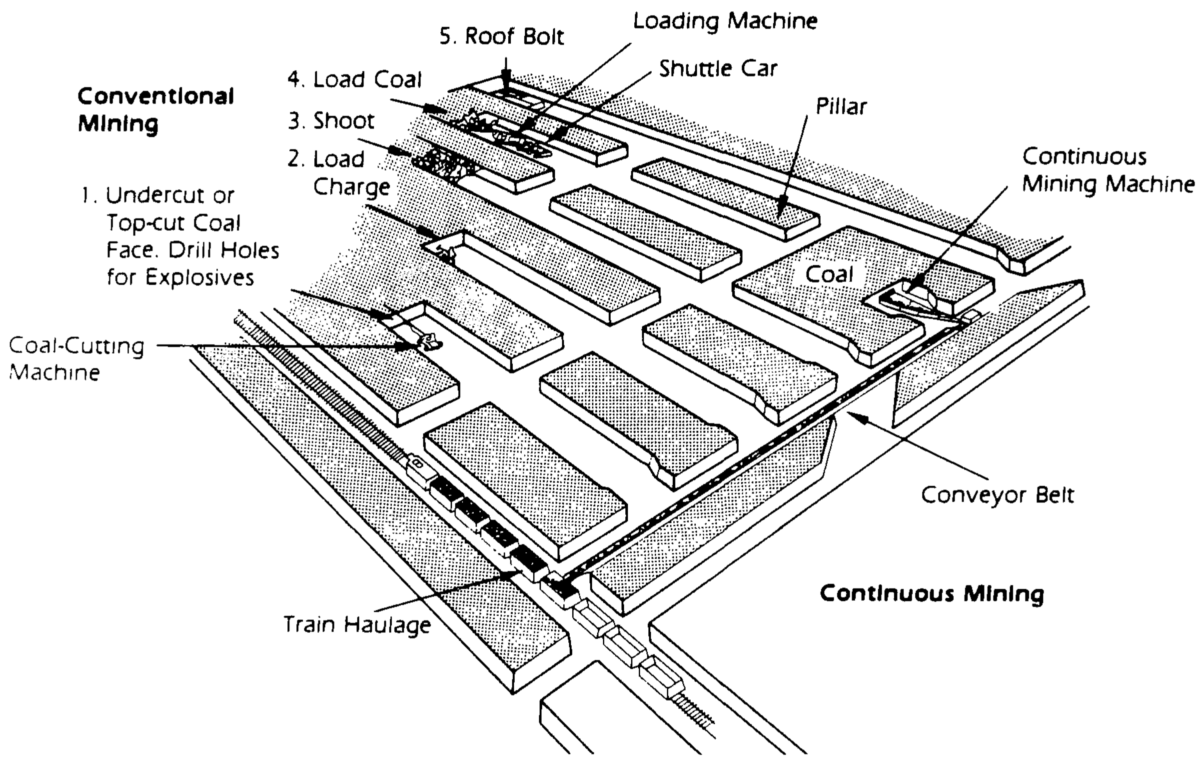
[14] For more information on coal mining, see Crickmeyer, D.F. and Zegeer, D.A., editors, 1981, or Stefanko, R., 1983.

EXHIBIT 2-2

SCHEMATIC DIAGRAM OF THE DEVELOPMENT OF A ROOM AND PILLAR MINE



Source: EIA Coal Data: A Reference, 1989.

eventual total roof collapse; in other cases, it may not be possible to safely remove any of the pillar which would cause limited or no collapse of the roof strata.

In room and pillar mining, methane is emitted by the coal that is mined, by the exposed surfaces of the pillars and by the coal beds above and below the mined seam. The amount of methane emitted by the surrounding strata is variable in room and pillar mining and depends on the extent to which the roof fractures and collapses. Typically, the collapse of the overlying strata and subsequent fracturing is not as extensive as that which occurs in longwall mines because any pillars or timbers left behind after mining can provide partial support to the roof strata and prevent complete collapse.

Longwall Mines. Longwall mining was originally developed in Europe in the 1800's and is presently the primary mining method employed there. The technique was introduced in the United States in the 1960's and accounted for about 25 percent of United States underground coal production in 1987 (about 84 million metric tons). Longwall mining is an extremely efficient and rapid method of mining coal, with ultimate resource recovery approaching 85 percent. However, the cost of equipping a longwall mine is much higher than that associated with equipping a conventional room and pillar mine.

There are two basic types of longwall mining: retreat and advance. The two methods are similar in the technologies employed and the associated methane emissions. Retreat longwall mining is used extensively in the United States longwall mines, and it is the method described here.

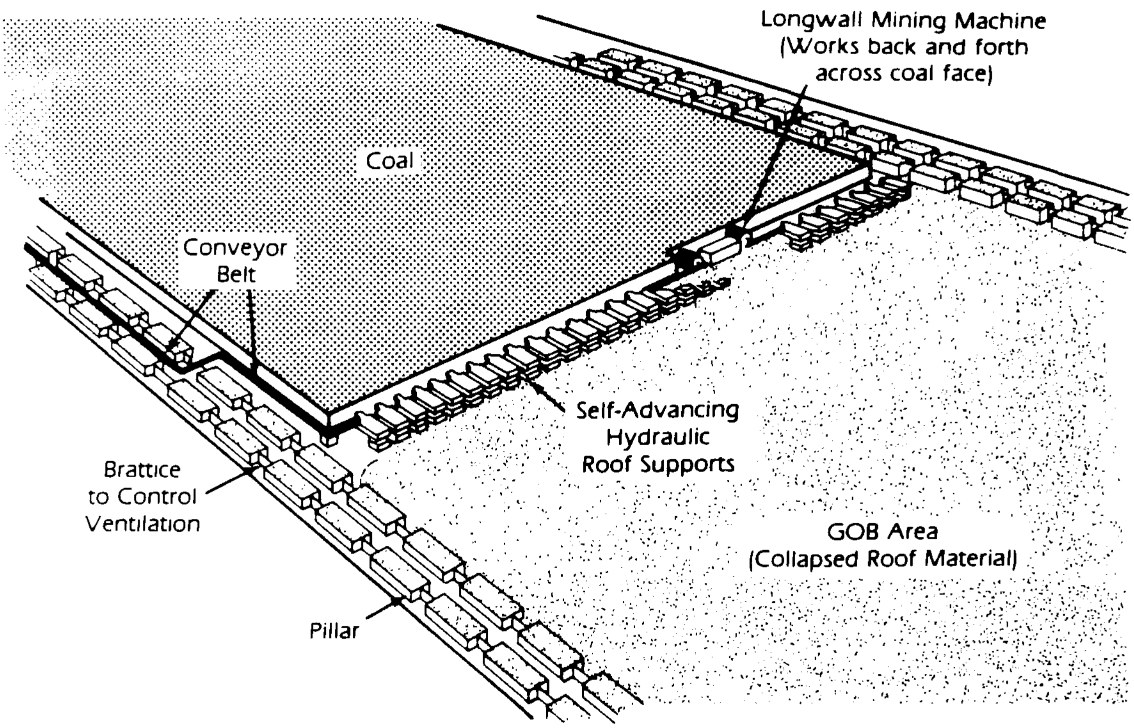
The development of a longwall mine begins by blocking out sections of coal into panels that can be 3,000 meters in length and from 90 to 300 meters in width. The development of panels is typically accomplished using continuous miners to drive entry ways (or gate roads) down the length of the panel, as shown in Exhibit 2-3. Once the side entries are completed, a set of entries is driven along the back of the panel to connect them.

After the panel is defined, movable coal cutting tools, a conveyor system, and a hydraulic roof support system are positioned lengthwise in the back entry. The cutting equipment and conveyor system operate underneath the roof support system. The cutting machine passes back and forth along the face of the coal exposed when the back entry was driven and cut coal falls onto the conveyor and is removed from the face. As the coal is removed, the hydraulic roof supports, along with the cutting and conveyor equipment, advance.

When the hydraulic roof support system is moved, the unsupported roof strata in the mined-out areas collapses. The floor strata also buckle creating a highly fractured zone above and below the mined-out coal seam. This fractured and collapsed area is called a "gob" (or

EXHIBIT 2-3

SCHEMATIC DIAGRAM OF LONGWALL MINE DEVELOPMENT



Source: EIA Coal Data: A Reference, 1989.

"goaf") area. The size of the gob area is a function of the depth of the mined seam, the nature of the rock overlying and underlying the coal seam, and the dimensions of the longwall panel. However, the gob usually affects an area of at least 100 meters above and 30 meters below the mined-out seam.[15]

Large volumes of methane are emitted during longwall mining operations both because these mines are typically deep and because of the rapid rate of coal production. Nearly 180 million cubic meters of methane (6.3 billion cubic feet) were exhausted from the ventilation

[15] Curl, S.J., 1978.

system of the United States mine with the highest methane emissions in 1985.[16] Much of the methane is emitted from the thin coal seams and rocks fractured in the gob area.

Surface Mining

Coal seams that are less than 60 meters below the surface are generally produced using surface mining techniques. Explosive charges fracture the strata overlying the targeted coal seam. After the overburden has been fragmented, draglines or power shovels remove the overburden and expose the coal seam.

As in underground mining, methane is released during surface mining by both the target coal seam and by the surrounding strata and any adjacent coal seams. However, the methane content of surface mined coal is estimated to be less than 3 cubic meters per ton (about 100 cubic feet/ton).[17] To date, there have been no measurements of methane emissions from surface mines because this methane is emitted directly into the atmosphere and poses no safety hazard to the miners. Thus, the amount of methane emitted during surface mining is uncertain.

Methane Emission Control Measures

Methane is a serious safety threat in coal mining because it is highly explosive in atmospheric concentrations of 5 to 15 percent. In the United States, the Mine Safety and Health Administration (MSHA) requires close monitoring of methane levels and careful design of mine ventilation systems to ensure that methane concentrations are kept at low levels. In mine entries used by personnel, methane levels cannot exceed 1 percent and in certain designated areas of the mine not frequented by mine personnel methane levels cannot exceed 2 percent. If these concentrations are exceeded, MSHA requires that the coal production cease and that the mine be evacuated until the ventilation system is able to dilute the methane concentration to acceptable levels.

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[16] Grau, R.H., 1987.

[17] For more information on these estimates, see Chapter III of this report and Exhibit 3-4.

Research on methods of methane control in underground coal mines has been undertaken because methane is such a serious and pervasive mining hazard, and because the costs of elevated methane concentrations can be high in terms of lost coal production. The main technique used for controlling methane concentrations in coal mines is ventilation. However, other emission control measures--such as horizontal boreholes, cross-measure boreholes, gob wells, and vertical degasification wells--have also been developed and are currently used in mines with high methane emissions. Each of these control options are discussed below.

Ventilation

Ventilation is a universal methane control technique in underground mines. Federal regulation requires that all coal mines continuously operate mechanical fans to circulate fresh air across the actively mined coal face. To keep methane concentrations below acceptable levels, several tons of air must be circulated through the mine for every ton of coal mined. For example, the large mines in the Pittsburgh coal seam in Pennsylvania will circulate between 5 and 23 tons of air for each ton of coal extracted.[18]

Currently, ventilation air is exhausted to the atmosphere at the mine shafts. Large quantities of this air are vented, with methane concentrations typically under 1 percent. In 1985, for example, the USBM estimated that 180 United States underground coal mines together vented more than 3.1 billion cubic meters of methane (more than 110 billion cubic feet) to the atmosphere through their ventilation systems. The ten largest methane emitting mines each vented over 195,000 cubic meters per day (almost 7 million cubic feet per day) of methane in this manner.[19]

Finding uses for these low concentration methane emissions has been the subject of research by the USBM, the U.S. Department of Energy (DOE), and others. The USBM has investigated the use of molecular sieves and membranes for stripping the low concentration methane from the ventilation air and producing a more concentrated product. However, this

[18] Skow, M.L., Kim, A.G., and Deul, M., 1980.

[19] Grau, R.H., 1987.

technology is not economic under current conditions. Another option under consideration is to feed the ventilation air into a boiler. In this case, the boiler must be nearby because it is not economic to transport low-energy ventilation air over large distances. Such an option might be attractive at mines that generate their own power.

In many mines, methane emissions into the mine workings can be controlled using ventilation alone by simply increasing the quantity of circulated air if methane concentrations are too high. In some mines, particularly very deep or otherwise very gassy mines, using a ventilation system alone to control methane would be prohibitively expensive. In these cases, other degasification technologies must be employed in conjunction with mine ventilation.

Horizontal Boreholes

One method to supplement the ventilation system is to install horizontal boreholes, a technique that has been used in coal mining since the 1800's. This technique consists of drilling boreholes from the mine workings into the unmined areas of the coal seam, as shown in Exhibit 2-4. These boreholes are typically tens of meters to hundreds of meters in length, and within a single mine several hundred boreholes may be drilled. The horizontal boreholes are connected to an in-mine vacuum piping system, which transports all of the methane released into the borehole out of the mine. Extensive precautions must be exercised to ensure that the integrity of the piping system is maintained in the mine workings.

By draining methane from the unmined coal, horizontal boreholes reduce methane emissions into the mine works and during mining. In some cases, 30 to 50 percent of the methane contained in the coal seam being mined may be removed with horizontal boreholes.

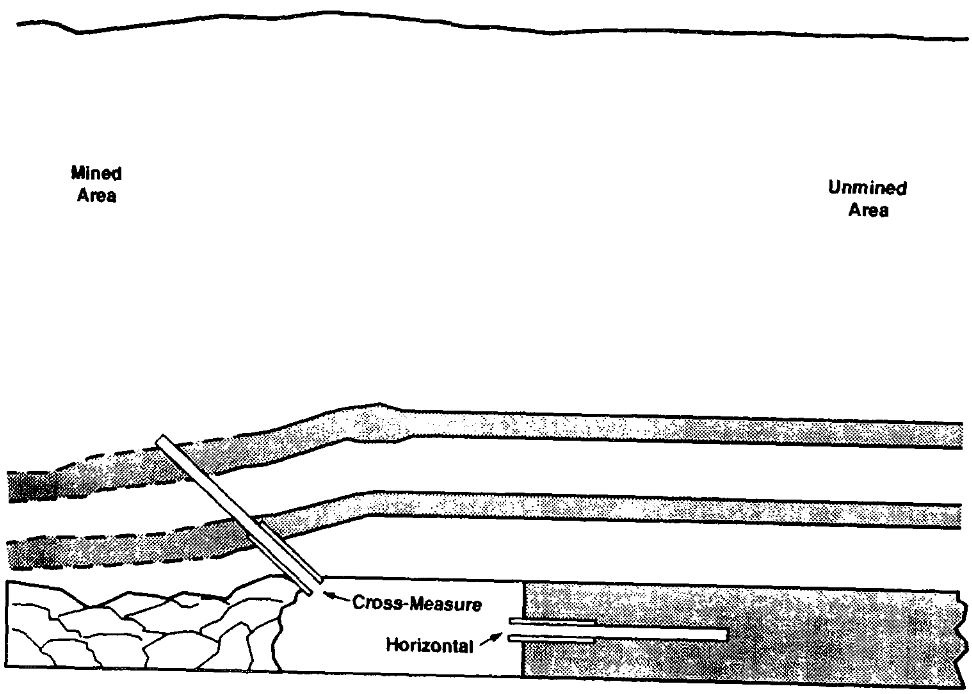
Cross-Measure Boreholes

While horizontal boreholes can degasify the target coal seam, they cannot effectively degasify the overlying or underlying coal and rock strata. To accomplish this type of degasification, cross-measure boreholes are used. Cross-measure boreholes have been used extensively in Europe but are not widely used in the United States.

These boreholes are similar to horizontal boreholes except they are drilled at an angle into the strata above and below the coal seam, usually into a future or active gob area, as shown in Exhibit 2-4. These boreholes are most effective in draining methane only after the gob area is created and the surrounding strata are fractured. As with horizontal boreholes, several boreholes are typically drilled and connected to an in-mine piping system which transports the methane to the surface.

EXHIBIT 2-4

SCHEMATIC DIAGRAM OF HORIZONTAL AND CROSS-MEASURE BOREHOLES

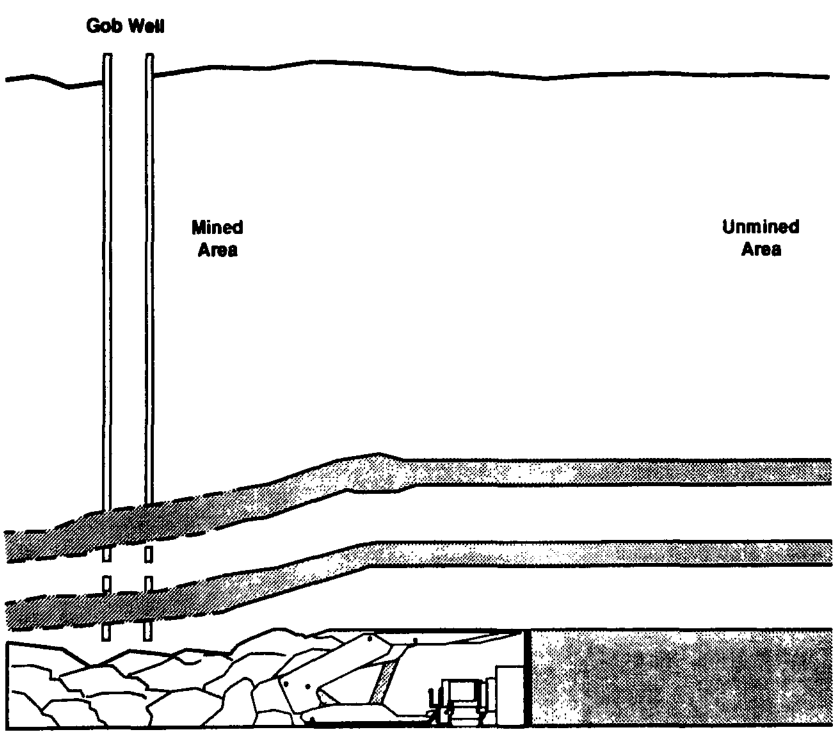


Prepared by: ICF Resources, 1990.

Gob Wells

The fractured gob area produced by longwall mines and some room and pillar mines is a significant source of methane, and in deep, gassy mines the ventilation system is often unable to sufficiently dilute the methane emitted from the gob into the mine workings. In these situations, wells can be drilled from the surface to drain methane from the gob area. Generally, these wells are drilled to a point 2 to 15 meters above the mined seam prior to the mining of the longwall panel. As mining advances under the gob well, the methane-charged coal and strata around the well will fracture. The methane emitted from this fractured strata flows into the gob well (often operating on a vacuum) and then to the surface, as shown in Exhibit 2-5.

EXHIBIT 2-5
SCHEMATIC DIAGRAM OF A GOB WELL



Prepared by: ICF Resources, 1990.

Methane production rates from gob wells can be very high, especially immediately following the fracturing of the strata as the longwall passes under the gob well. One mining company that recovers methane from its gob wells for sale to a pipeline reports that the wells may initially produce at rates in excess of 56,000 cubic meters per day (2 million cubic feet per day). Over time, this production rate declines until a relatively stable rate is achieved, typically in the 2,800 cubic meters per day (100,000 cubic feet per day) range.[20] Initially, this gob gas may be of pipeline quality (37 Kj/m^3 or 1,000 Btu/ft^3). Over time, the quality may fall as methane emissions decline and additional amounts of mine air flow into the well and dilute the methane. With careful monitoring of the vacuum exerted on the well, however, it may be possible under certain conditions to maintain production of a high quality gas over much of the life of the well.

Most methane produced from gob wells is currently vented to the atmosphere. One notable exception to this is in Alabama, where over 849,000 cubic meters of methane per day (more than 30 million cubic feet per day) from 80 gob wells are captured and sold as natural gas. Since this program was initiated six years ago, over 1.1 billion cubic meters (almost 40 billion cubic feet) of methane have been captured and utilized instead of being vented to the atmosphere.[21] However, even this program has probably only captured 30 to 40 percent of the methane released as a result of this mine's coal mining activities.

Vertical Wells

The optimum method for controlling methane emissions is to pre-drain the methane from the coal and strata before mining operations begin. Vertical degasification wells are similar to conventional oil and gas wells and are drilled into the coal seam several years ahead of the active mining area. Usually, these wells must be stimulated to create a pathway in the coal to facilitate gas flow. In addition, in some areas these wells may produce large quantities of water and small volumes of methane during the first several months they are on-line. As this water is removed, the pressure on the coal seam is lowered, the methane desorbs, and the methane production rate increases, as shown in Exhibit 2-6.

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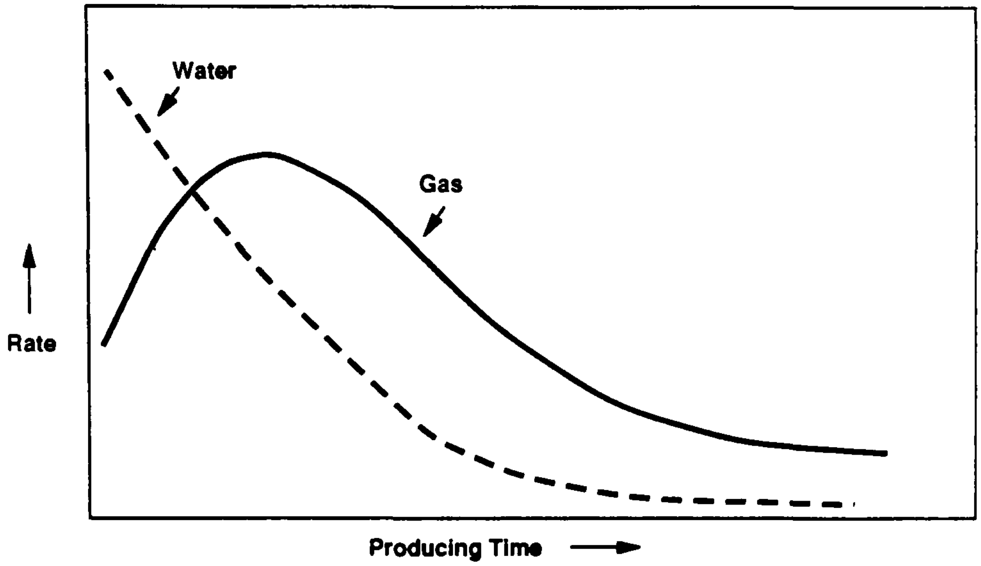
[20] Dixon, C.A., 1989.

[21] Dixon, C.A., 1989.

EXHIBIT 2-6

GAS AND WATER PRODUCTION CURVES FOR A TYPICAL VERTICAL WELL



Prepared by: ICF Resources, 1990.

Pre-drainage of methane using vertical wells is a very effective method of reducing the methane content of coal beds and, consequently, reducing the methane emissions from the eventual mining operation. Diamond and others document that as much as 79 percent of the methane in-place in the mined seam can be removed from coal using vertical degasification wells drilled more than 10 years in advance of mining.[22] Although vertical wells are not widely used in the coal mining industry, their use is increasing in "stand-alone" gas production operations.

Post-Mining Emissions

The time required for a coal to release all of its methane can vary from several days to

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[22] Diamond, W.P., Bodden, W.R., Zuber, M.D., and Schraufnagel, R.Z., 1989.

several months. Because the residence time in the mine of the mined coal is generally less than one day, a portion of the methane is released after the coal has left the mine, during the subsequent processing, transportation, and utilization.

Coal Processing

Coal processing involves transforming the mined coal into a product acceptable for sale. Metallurgical coal is used to produce coke, a porous carbon solid derived from the destructive distillation of coal. Coke is used in the smelting of iron ore and the manufacturing of steel. Thermal coal is used to generate heat, which in turn is used for electric power generation, industrial heating, and residential heating. The primary points during coal processing where methane emissions are accelerated are breaking, crushing, and thermal drying.

The greatest amounts of post-mining methane emissions occur when the coal is crushed and sized. The smaller coal size and the creation of increased surface area enables the methane on these surfaces to rapidly desorb and be emitted. The two principal coal size reduction processes are:

- **Primary breaking and crushing.** During this initial breaking and crushing methane emissions are high as the mined coal is reduced to 5-15 cm lumps.

- **Secondary breaking and crushing.** Additional breakage and methane release results from the handling of the coal as it is blended, cleaned, moved in storage, loaded and transported, unloaded, stored, and prepared for use by the customer.

Drying is accomplished by blowing heated air through the coal in a drying chamber, driving off the excess moisture. In metallurgical coals, the coal surfaces are generally the only part that is dried. In some of the higher moisture thermal coals, the coal is dried more deeply to remove a percentage of the internal (inherent) moisture as well. Because the desorption rate of methane from coal is accelerated at elevated temperatures, thermal drying will accelerate methane emissions. All methane emitted during size reduction and thermal drying is currently vented to the atmosphere.

Coal Transportation

World coal transportation is dominated by railroads, which account for over 60 percent of total coal transportation. Transportation by barge and ship account for an additional 10 to 20 percent.[23] The remaining transportation methods are divided among trucks, conveyors, tramways, and slurry pipelines. The methane emissions from coal during transportation are released directly to the atmosphere. Even in those transportation systems that are enclosed, such as a ship's hold, the required ventilation system will ultimately exhaust the methane into the atmosphere.

Coal Utilization

The largest use of coal is for the thermal coal market, accounting for about 80 percent of world coal production. Metallurgical coal accounts for the remaining 20 percent of production. For thermal coal, the remaining methane in the coal will be emitted during the final crushing and pulverization of coal, prior to its use at the utility plant. Because this process occurs within a closed system, the methane is burned along with coal upon injection into the boiler.

During the production of coke, the end-use for metallurgical coal, the coal is heated to very high temperatures to drive off the volatile matter and to produce a nearly pure carbon material. Prior to heating, the coal is often crushed to less than 5 mm, with the emitted methane vented to the atmosphere. During the coking process, a mixture of methane, carbon dioxide, and other gases are driven off and collected as coke gas. In modern coke ovens, the coke gas is captured and utilized as a fuel source, although old coke ovens (known as "beehives") in use in lesser developed countries still vent the coke gas into the atmosphere.

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[23] IEA Coal Information, 1987.

CHAPTER III

Methane Emissions Estimate For Global Coal Mining

One of the goals of this study was to estimate the quantity of methane emitted to the atmosphere from coal mining and utilization both on a global and country-by-country basis. While global estimates of methane emissions from coal mining and utilization have been prepared previously as part of comprehensive studies of the global methane budget, these studies do not provide information on methane emissions from coal mining by country, and in many cases they do not fully document the methodology used to arrive at their estimates.

This study estimates country-specific methane emissions from coal mining, although these estimates must be considered highly approximate because of data limitations and other uncertainties. By providing broad country-by-country estimates, however, this report provides information of use to scientists, technical experts and policy makers who need to set priorities to guide additional research. Further, in developing and explaining the methodology used to generate these estimates, the report can serve as a foundation for future research and for refining the methodology used to prepare emission estimates for coal mining.

This chapter has four sections. In the first section, the methodologies used to estimate methane emissions from United States coal mines is explained. In the second section, methane emissions for other coal producing countries are estimated. The third section summarizes the global estimates contained in this study and compares the estimates to others found in the literature. Finally, the fourth section discusses the key uncertainties in this analysis and their potential impacts.

Methane Emissions From United States Coal Mines

Methodology

Methane emissions from coal mining and coal utilization in the United States were determined on a state-by-state basis using data on the coal tonnage mined, the type of mining used (underground or surface), the estimated methane content of the coal, and a mining-based emissions equation. Data on coal production and type of mine were obtained from federal and state reports. Where available, methane content data were obtained from measurements by USBM, DOE, the Gas Research Institute (GRI), and industry. For those states with no methane content data, a methane content value was estimated based on the rank and depth of the coal seams being mined in the state. A mining-based emissions equation was used to estimate the total methane emissions from a mine, including methane emissions from the mined coal, from coal left in the mine, and from associated coal seams and strata. This factor was derived from a statistical analysis of the measured methane emission rates from 59 United States mines. In addition to estimating methane emissions from the mining operation itself, the quantity of methane released by mine degasification systems and the various post-mining processes was also estimated. Each of these steps is discussed in more detail below.

United States Coal Production Data. Coal production data for the United States in 1987 were obtained from official state reports and from the U.S. Energy Information Administration.[24] Because the methane content of shallow coal and deeply buried coal is significantly different, coal production data were separated into underground and surface mining categories, as shown in Exhibit 3-1. Five major coal producing states in the Appalachian Basin (Kentucky, West Virginia, Pennsylvania, Virginia, and Ohio) accounted for over 70 percent of total underground coal production. Wyoming dominated surface mined coal production with nearly 30 percent of total United States surface coal production.

United States Methane Content Data. Methane content values for underground and surface mined coal were estimated for each coal producing basin and the associated states. The

[24] 1987 coal production data were used because this is the most recent year for which international coal production data were available.

EXHIBIT 3-1

UNDERGROUND, SURFACE, AND TOTAL COAL PRODUCTION IN THE UNITED STATES, 1987

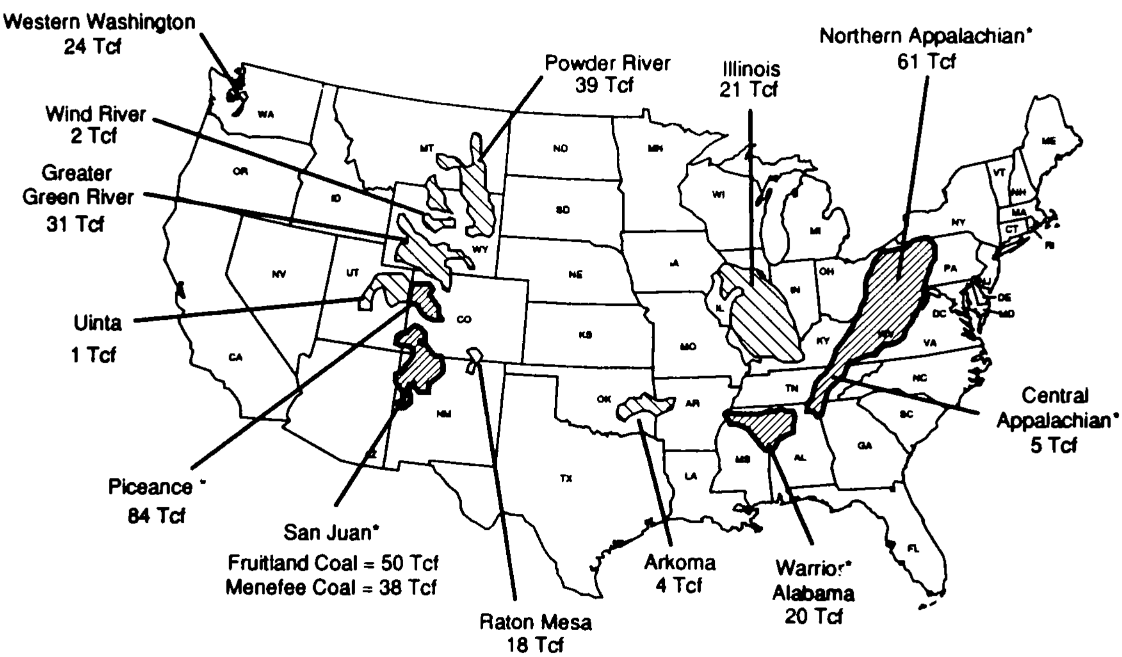
State	Coal Production (Thousand Metric Tons)		
	Underground	Surface	Total
ALABAMA	12,999	10,099	23,098
ALASKA	0	1,354	1,354
ARIZONA	0	10,323	10,323
ARKANSAS	0	61	61
CALIFORNIA	0	42	42
COLORADO	5,115	7,959	13,074
ILLINOIS	34,039	19,623	53,662
INDIANA	2,220	28,781	31,001
IOWA	57	367	425
KANSAS	0	1,829	1,829
KENTUCKY	83,592	64,933	148,525
LOUISIANA	0	2,496	2,496
MARYLAND	2,177	1,384	3,562
MISSOURI	0	3,885	3,885
MONTANA	0	31,207	31,207
NEW MEXICO	562	16,794	17,357
NORTH DAKOTA	0	22,807	22,807
OHIO	11,440	20,812	32,252
OKLAHOMA	0	2,590	2,590
PENNSYLVANIA	34,623	28,376	62,999
TENNESSEE	4,366	1,395	5,762
TEXAS	0	45,840	45,840
UTAH	14,976	0	14,976
VIRGINIA	33,322	6,757	40,079
WASHINGTON	0	4,036	4,036
WEST VIRGINIA	97,224	26,094	123,318
WYOMING	96	133,125	133,221
TOTAL	**336,810**	**492,969**	**829,779**

Source: EIA Coal Production, 1987.

major coal basins in the United States are shown in Exhibit 3-2. Four techniques were used to develop the methane content estimates, depending on the type and quality of the data available and the mining method employed.

EXHIBIT 3-2

MAJOR U.S. COAL BASINS AND COALBED METHANE RESOURCES



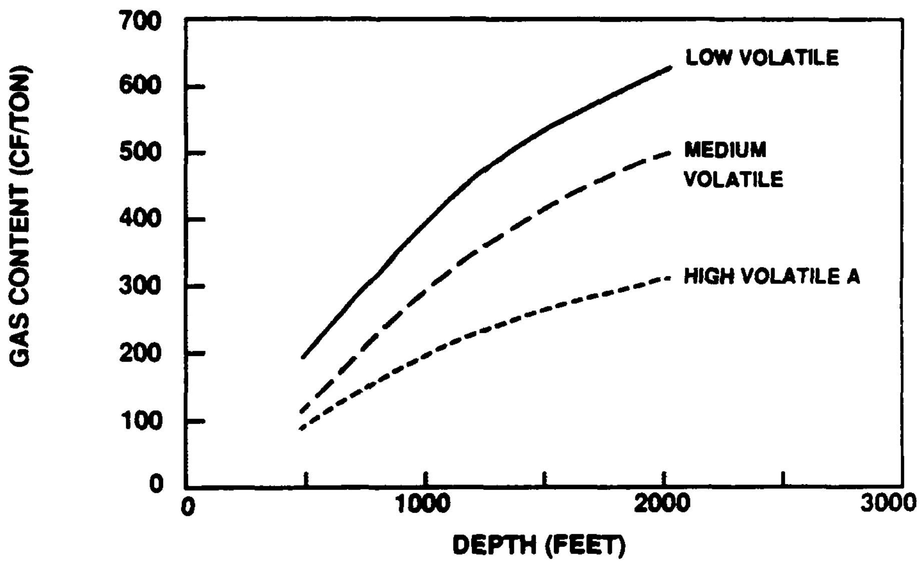
* Detailed geologic appraisals completed by GRI/ICF Resources

Prepared by: ICF Resources, 1990.

Where available, detailed assessments of the quantity of methane content in coal seams were used. To date, these assessments have been prepared by the GRI for five of the major United States coal basins--Northern Appalachian, Central Appalachian, Warrior, San Juan, and Piceance--which together accounted for 78 percent of United States underground coal production in 1987.[25] These studies estimated the quantity of methane in coal seams more than 400 feet deep. In each basin, a relationship between methane content and the depth and rank of the coal seams was derived using data from the USBM Gas Content Database and other available sources.[26] Over 1,200 methane content measurements were used in these evaluations. The methane content and depth/rank relationship for the Central Appalachian Basin is shown in Exhibit 3-3.[27]

EXHIBIT 3-3

RELATIONSHIP BETWEEN GAS CONTENT AND DEPTH
CENTRAL APPALACHIAN BASIN



Source: Kelafant, J.R., and Boyer, C.M., 1988.

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[25] Kelafant, J.R., Wicks, D.E., and Kuuskraa, V.A., 1988; Kelafant, J.R., and Boyer, C.M., 1988; Kelso, B.S., Wicks, D.E., and Kuuskraa, V.A., 1988; McFall, K.S., Wicks, D.E., and Kuuskraa, V.A., 1986; McFall, K.S., Wicks, D.E., Kuuskraa, V.A., and Sedwick, K.B., 1986.

[26] Diamond, W.P., LaScola, J.C., and Hyman, D.M., 1986.

[27] Kelafant, J.R., and Boyer, C.M., 1988

The GRI assessments also provided an estimate of the tonnage of coal present in the basins, which was combined with the estimated methane content to determine an average methane content for underground mined coal in each basin.

In four other key coal producing areas (the Uinta, Illinois and Green River Basins, and the Pennsylvania Anthracite fields) methane content data were available but the basins have not been studied in detail. For three of these basins[28], methane and coal resource estimates prepared by the DOE were used to approximate the methane content of underground mined coal. For the fourth basin[29], no basin-wide methane and coal resource estimates were available and the methane content of underground mined coal was estimated from the arithmetic average of the available methane content data for the basin.

Available data on the methane content of surface mined coal were also obtained from the USBM Methane Content Data Base.[30] For these estimates, only methane content values measured in coal seams less than 200 feet deep (the approximate depth limit for surface mined coal) were used. The average methane content of surface-mined coal was the arithmetic average of the shallow coal methane content values.

Finally, no methane content data were available for some of the smaller coal basins in the United States. For these basins, average methane content values were derived by analogy with coal basins with methane content estimates, based on the rank, depth, and age of the coal being mined. Exhibit 3-4 summarizes the methane content estimates used for the different coal basins.

Mining Emissions Equation - Underground Mines. During the mining of coal, the total quantity of methane emitted from the mine exceeds the in-situ methane content of the mined coal. This difference is due to 1) methane emissions from coal pillars left in the mine for support and, more importantly, 2) methane emissions from the methane charged coal seams and rock

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28 Illinois, Uinta, and Green River Basins.

29 Pennsylvania Anthracite Fields.

30 Diamond, W.P., LaScola, J.C., and Hyman, D.M., 1986.

EXHIBIT 3-4

AVERAGE METHANE CONTENT IN MINED COAL

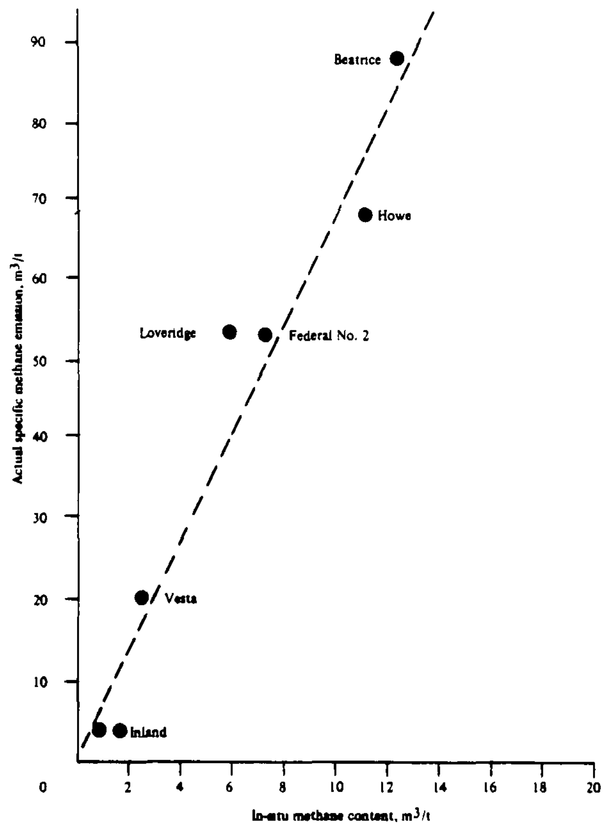
Basin or State	Estimated Average Methane Content (m^3/metric ton)
Underground Mined Coal	
Northern Appalachian[1]	5.4
Central Appalachian[2]	10.4
Warrior[3]	10.0
Piceance[4]	8.0
San Juan[5]	7.1
Illinois[6]	1.8
Uinta[6]	1.3
Green River[6]	1.3
Pennsylvania Anthracite Fields[7]	4.4
Surface Mined Coal	
Appalachian (including Warrior)[7]	1.55
Illinois[7]	1.22
Powder River[7]	0.10
Arkoma[7]	3.40
San Juan[7]	0.48
Alaska[8]	0.10
Arizona[9]	0.48
Arkansas[10]	1.22
California[8]	0.10
Louisiana[8]	0.10
North Dakota[8]	0.10
Texas[8]	0.10
Washington[8]	0.10

1) Kelafant, J.R., Wicks, D.E., and Kuuskraa, V.A., 1988
2) Kelafant, J.R., and Boyer, C.M., 1988
3) McFall, K.S., Wicks, D.E., and Kuuskraa, V.A., 1986
4) McFall, K.S., Wicks, D.E., Kuuskraa, V.A., and Sedwick, K.B., 1986
5) Kelso, B.S., Wicks, D.E., and Kuuskraa, V.A., 1988
6) Mroz, T.H., Ryan, J.G., and Byrer, C.W., 1983
7) Diamond, W.P., LaScola, J.C., and Hyman, D.M., 1986
8) Extrapolated from the Powder River Basin
9) Extrapolated from the San Juan Basin
10) Extrapolated from the Illinois Basin

strata surrounding the mined seam. The quantity of methane emitted varies from mine to mine depending on mining method, tonnage mined, and the age of the mine. One study by the USBM, shown in Exhibit 3-5, indicated that the methane emissions during mining exceeded the in-situ methane content by a factor ranging from 6 to 9.[31] Methane emissions factors for

EXHIBIT 3-5

METHANE EMISSIONS VS. IN-SITU METHANE CONTENT - SELECTED U.S. COAL MINES



Source: Kissell, F.N., McCulloch, C.M., and Elder, C.H., 1973.

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[31] Kissell, F.N., McCulloch, C.M., and Elder, C.H., 1973.

mining have also been estimated in other major coal producing countries of the world (especially the European countries), yielding methane emissions factors ranging from 2 to 5.[32]

The most accurate method of calculating methane emissions would be to derive an emissions factor for every mine of interest. For United States mines, data on methane emissions are publicly available through MSHA and from periodic summary reports by the USBM. Given that there are almost 1,900 active underground mines in the United States alone, however, such an analysis was beyond the scope of the study.

Thus, the methane emissions estimates derived by this study were based on a United States average methane emissions equation, which was derived using data from a previous study on methane emissions and the previously described GRI basin assessments.[33] A comparison was made between actual methane emissions (per ton of coal mined) and the estimated in-situ methane content (per ton of coal mined), similar to the approach used by the USBM in 1973 and shown in Exhibit 3-5. Results of this comparison and a least-squares linear regression of the data are shown in Exhibit 3-6. In addition, the least squares linear regression and a 1-standard deviation range of the data are also shown. The equation obtained from the linear regression, in cubic meters of methane emitted per metric ton of coal mined, is:

$$\text{Methane Emissions, in Cubic Meters of Methane per Metric Ton of Coal Mined} = (2.04 \times \text{In-Situ Methane Content}) + 8.16$$

$$(\text{t Statistic} = 5.10,\ r^2 = 0.35)$$

Both the scatter plot of the regression and the r-squared of the regression indicate that there is a great deal of uncertainty with respect to methane emissions per ton of coal mined. Using one standard deviation around the mean (regression line) as a measure of uncertainty, it appears that the actual methane emissions value could be up to 23 percent higher or lower than the predicted level.

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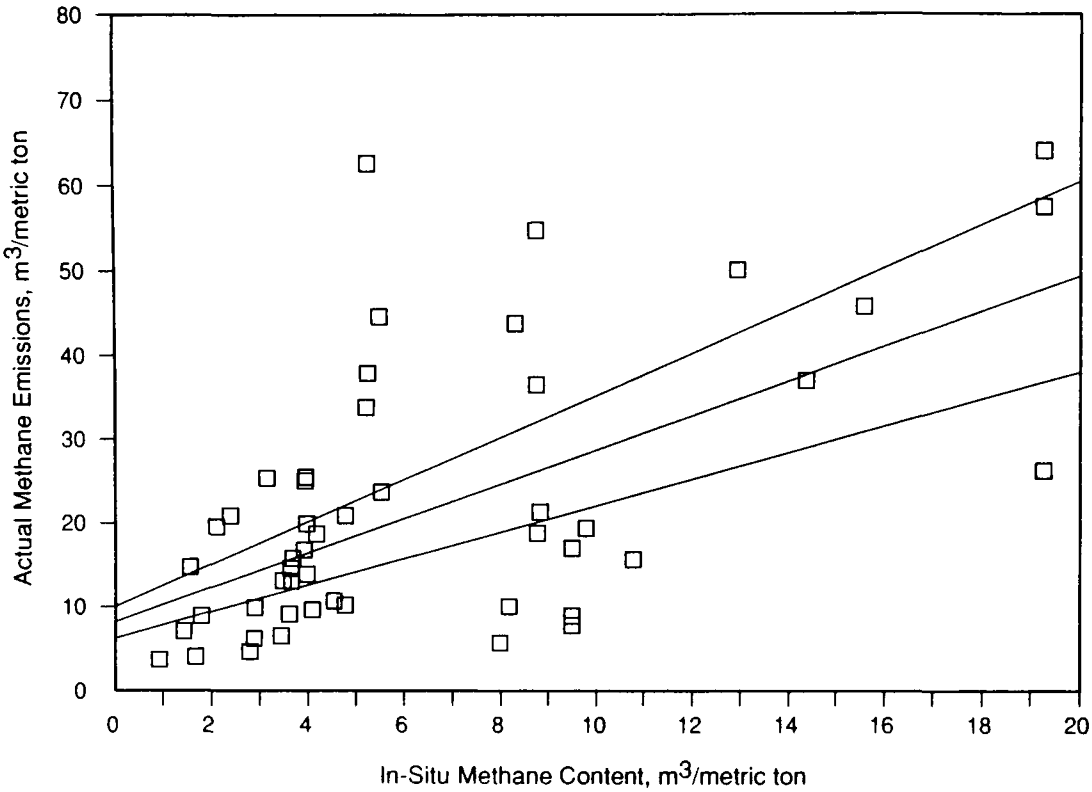
[32] Curl, S.J., 1978.

[33] Irani, M.C., Jeran, P.W. and Deul, M., 1974.

EXHIBIT 3-6

METHANE EMISSIONS VS. IN-SITU METHANE CONTENT - 59 U.S. COAL MINES



Source: Irani, M.C., Jeran, P.W., and Deul, M., 1974, and ICF Resources, 1990.

This equation was combined with the average in-situ methane contents established for the various coal producing states to estimate the methane emissions per ton of coal mined. When combined with the tons of underground coal production from each state, an overall estimate of the quantity of methane emitted from underground mines was obtained. A range of methane emissions was also estimated to reflect the uncertainties inherent in these estimates.

Mining Emissions Factor - Surface Mines. The methane contents of surface mined coal seams are substantially lower than those of deeper, underground mined coal seams, as discussed previously. The quantity of methane emitted from surface mines may be significant, however, since surface mined coal represents nearly 60 percent of the total coal production in the United States.

As with underground mines, the total quantity of methane emitted by surface mines will always be larger than the quantity of methane contained in the coal being mined, because of the contribution of methane from the coal seams and strata adjacent to the mined seam that are disturbed during mining. Because of this, the previously established methane emission equation should be applicable to surface mined coal. However, surface coal mines typically have higher coal recovery rates (80 percent) than underground coal mines (50 percent). The underground mining emissions equation (derived from underground coal production and methane emissions rates) was therefore modified to account for the increase in coal recovery associated with surface coal mines. The estimated methane emissions (per ton of coal mined) for surface mined coal were decreased by 37.5 percent to incorporate the higher recovery rates associated with surface mines.

Degasification System Emissions. Many underground mining operations in the United States employ degasification systems to control methane levels in the mine workings. With the exception of a limited number of mines, primarily in Alabama, all of the methane produced by degasification systems is vented to the atmosphere and must be included in any estimate of total mining-related methane emissions.[34] Estimates of methane produced from gob wells associated with longwall mining operations were used to represent the contribution from degasification methods to the total methane emissions estimate. It is recognized that other degasification systems, such as horizontal and cross-measure boreholes or vertical wells, also produce and emit methane but these systems were not included in this estimate.

In 1987, 101 longwall systems were operating in the United States.[35] For this study, it was assumed that it would take an average of nine months to completely mine a longwall panel, which would imply that a total of 133 longwall panels could have been mined in 1987. The

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[34] The USBM data on which the emission equation was based measures methane contained in the ventilation air only. Thus, this equation alone would not reflect the additional methane emissions from degasification systems.

[35] Layne, A.W., Siriwardane, H.J. and Byrer, C.W., 1988.

number of gob wells producing from each longwall panel varies depending upon the length of the panel and the quantity of methane to be vented. In addition, the length of time these wells vent methane and the quantity of methane vented also vary. In this analysis, it was assumed that three gob wells per longwall panel would be drilled and that they would vent methane for about nine months.[36] An average methane emission rate of 14,160 cubic meters per day (500,000 cubic feet per day) per well was used for gob wells in all states, with the exception of Alabama.[37] Based on published data from 80 gob wells, an average gob well emission rate of 25,485 m^3/day (900,000 cubic feet per day) was used for Alabama.[38]

Based on these assumptions, an estimated 2.2 billion cubic meters (over 77 billion cubic feet) or 1.5 million metric tons of methane was emitted to the atmosphere from degasification systems. Thus, these emissions could account for 20 percent of total methane emissions. Only one state, Alabama, currently has mining operations which utilize this methane rather than venting it to the atmosphere. In 1987, mining operations in Alabama captured and sold almost 310 million cubic meters (10 billion cubic feet), or about 0.2 million metric tons, of methane into the natural gas pipeline systems. The utilized methane was not included in the 1.5 million metric tons estimated as being vented by degasification systems.

Post-Mining Emissions. Because methane desorption and emission is not instantaneous, some methane will still be contained in the coal after it has left the mine. It was estimated that, on average, 25 percent of the methane content of mined coal (i.e., the in-situ methane content) could be emitted after the coal has left the underground mine.

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[36] The number of gob wells per panel and their production lifetime are variable, dependent upon specific geologic and mining conditions at the subject mine. Currently, the optimal number of wells is determined often by trial and error, and has ranged from one to six wells per panel. In this analysis, it was assumed that three wells would be used, which is consistent with the selection of a three-well spacing reported by Dixon, C.A., 1989, for certain mines in Alabama.

[37] Layne, A.W., Siriwardane, H.J., and Byrer, C.W., 1988; Pothini, B.R., 1988; Kline, R.J., Mokwa, L.P., and Blankenship, P.W., 1987.

[38] Alabama State Oil and Gas Board, 1986-1989; Dixon, C.A., 1989.

Results

The total methane emissions estimate for the United States during 1987 was derived from three separate categories of emissions: emissions directly from the mine for both underground and surface mines; emissions from degasification activities associated with underground mines, and post-mining emissions from underground-mined coal. Based on this study, an estimated 7.0 million metric tons (with a range of 5.4 to 8.6 million metric tons) of methane were emitted to the atmosphere as a result of coal mining and utilization in 1987 in the United States, as shown in Exhibit 3-7. By far the largest source of methane emissions was the mining operation itself. In the United States, 4.2 to 6.6 million metric tons of methane, or about 78 percent of the total methane emissions, were released directly from the mine workings. Methane emissions from degasification systems accounted for about 18 percent of the total emission (1.0 to 1.5 million metric tons) and post-mining methane emissions contributed the remaining 4 percent of the total (0.2 to 0.4 million metric tons), Exhibit 3-8.

Of the total methane emitted, about 88 percent (4.7 to 7.5 million metric tons) came from underground mined coal and the remaining 12 percent (0.6 to 1.1 million metric tons) was released from surface mined coal. Four states - West Virginia, Virginia, Pennsylvania, and Alabama - accounted for almost 75 percent of the total United States emissions. In these states, deep longwall mines are the major source of methane emissions.

In addition, average methane emissions per ton of coal mined using underground or surface methods were estimated by dividing estimated emissions from each mining method by the total amount of coal mined using that method. This approach yielded estimated emissions of 27.1 cubic meters of methane per metric ton for underground mined coal and 2.5 cubic meters of methane per metric ton for surface mined coal. These estimated methane emission values are not representative of any specific mine or area because they represent the aggregate of all United States coal mines and basins. They reveal a significant difference in emissions between underground and surface mines, however, and can also provide a useful benchmark for comparison with other studies.

EXHIBIT 3-7

ESTIMATED METHANE EMISSIONS FROM U.S. COAL MINING AND UTILIZATION BY STATE, 1987

State	Estimated Methane Emissions (Million Metric Tons)		
	Underground	Surface	Total
ALABAMA	0.3	<0.1	0.3
ALASKA	0	<0.1	<0.1
ARIZONA	0	<0.1	<0.1
ARKANSAS	0	<0.1	<0.1
CALIFORNIA	0	<0.1	<0.1
COLORADO	0.2	<0.1	0.2
ILLINOIS	0.4	0.1	0.5
INDIANA	<0.1	0.1	0.1
IOWA	<0.1	<0.1	<0.1
KANSAS	0	<0.1	<0.1
KENTUCKY	0.8	0.2	1.0
LOUISIANA	0	<0.1	<0.1
MARYLAND	0.1	<0.1	0.1
MISSOURI	0	<0.1	<0.1
MONTANA	0	<0.1	<0.1
NEW MEXICO	<0.1	<0.1	<0.1
NORTH DAKOTA	0	<0.1	<0.1
OHIO	0.3	<0.1	0.3
OKLAHOMA	0	<0.1	<0.1
PENNSYLVANIA	0.6	0.1	0.7
TENNESSEE	<0.1	<0.1	<0.1
TEXAS	0	<0.1	<0.1
UTAH	0.2	0	0.2
VIRGINIA	0.9	<0.1	0.9
WASHINGTON	0	<0.1	<0.1
WEST VIRGINIA	2.3	0.1	2.4
WYOMING	<0.1	<0.1	0.1
	=====	=====	====
TOTAL	**6.1**	**0.9**	**7.0**
POTENTIAL RANGE	**4.7-7.5**	**0.6-1.1**	**5.4-8.6**

EXHIBIT 3-8

ESTIMATED METHANE EMISSIONS FROM U.S. COAL MINING AND UTILIZATION BY MINING METHOD AND SOURCE

Mining Method	Estimated Methane Emissions (Million Metric Tons)			
	Mine Operations	Degasification Systems	Post-Mining Processes	Total
Underground	4.6 (3.6-5.5)	1.2 (1.0-1.5)	0.3 (0.2-0.4)	6.1 (4.7-7.5)
Surface	0.9 (0.6-1.1)	0	0	0.9 (0.6-1.1)
Total (Range)	**5.5 (4.2-6.6)**	**1.2 (1.0-1.5)**	**0.3 (0.2-0.4)**	**7.0 (5.4-8.6)**

Methane Emissions from Foreign Coal Producing Countries

As indicated by the discussion above, estimating methane emissions from coal mining is very data-intensive. Even in the United States, where data on coal production, in-situ methane content, and methane emissions through mine ventilation systems are collected and analyzed, the estimates are based on major assumptions and have a degree of uncertainty. Estimating methane emissions from coal mining in other countries is even more uncertain because access to data is limited, particularly in some of the other major coal producing nations such as China, the Soviet Union, and Poland.

Since efforts to collect and assess data from the many coal producing countries was beyond the scope of this study, methane emissions from United States coal mines were used as the analog for estimating methane emissions from other coal producing countries of the world. To estimate country-specific methane emissions, the estimated average methane emission rates for surface and underground mining in the United States were combined with the 1987 coal production of each country. To reflect the uncertainty inherent in applying these values to other countries, the United States methane content ranges were expanded by an additional 10 percent. Thus, the methane content ranges used to estimate international methane emission were 18.8 to 36.7 m^3/ton for underground mined coal and 1.7 to 3.4 m^3/ton for surface mined coal.

This assumption reflects the fact that actual methane emissions could be higher or lower than those estimated for the United States depending on factors such as (1) the methane content of coal being mined, (2) the age of the mine, (3) the type of mining method used, and (4) the type of degasification systems used. As better data become available for various countries, country-specific mining emissions equations should be created and these estimates refined.

Until such data are available, however, this approach represents a reasonable first approximation of country-by-country methane emissions associated with coal mining. Because it distinguishes between underground and surface mining, the major source of variation in methane emissions is accounted for. Further, since the coal ranks mined in the United States are generally similar to those mined in other coal producing countries, the approach should provide a reasonable estimate of emissions. Finally, while it is difficult to determine a particular country's emissions with certainty, this method provides information about the order of magnitude of emissions between different countries, which is important to both policy makers and technical researchers in developing priorities for future research efforts.

Coal production statistics were collected from a number of sources including United States Department of Energy reports, World Bank studies, and various foreign country reports.[39] Underground and surface coal production in 1987 for the ten largest foreign coal producing countries is shown in Exhibit 3-9. These ten countries represent 85 percent of total foreign coal production, producing 3.2 billion metric tons of coal out of a foreign total of 3.8 billion metric tons of coal. China was the largest coal producing country, with more than 900 million metric tons of reported coal production in 1987.

Estimated methane emissions from United States and foreign coal mining activities is shown in Exhibit 3-10. The figure is divided to show methane emissions from the ten largest foreign coal producing countries (and the United States) and the secondary coal producing countries. As the exhibit shows, the methane emissions from the ten primary foreign coal producing countries are estimated to account for over 90 percent (34 to 54 million metric tons) of the total world methane emissions (33 to 64 million metric tons). China, the world's largest

[39] See for example, IEA Coal Information, 1987; IEA Coal Statistics, 1987; EIA Coal Production, 1987.

EXHIBIT 3-9

UNDERGROUND, SURFACE, AND TOTAL COAL PRODUCTION IN THE TEN PRIMARY FOREIGN COAL PRODUCING COUNTRIES, 1987

	1987 Coal Production (Million Metric Tons)		
Country	Underground	Surface	Total
China	891	37	928
U.S.S.R	429	331	760
East Germany	0	303	303
Poland	193	73	266
Australia	47	143	190
West Germany	79	109	188
India	85	100	185
South Africa	111	62	173
Czechoslovakia	26	100	126
United Kingdom	86	16	102
TOTAL	**1,947**	**1,274**	**3,221**

Source: IEA Coal Information, 1987; IEA Coal Statistics, 1987; EIA Coal Production, 1987.

coal producer, was estimated to release 34 percent (12 to 20 million metric tons) of the world's methane emissions. The top four foreign coal producers--China, the Soviet Union, the United States, and Poland--were responsible for about 75 percent (27 to 43 million metric tons) of the world's estimated emissions.

Coal mining operations in many European countries employ extensive degasification systems.[40] Of the methane produced by the degasification methods, from 5 to 90 percent is utilized as a fuel source. Using these published values of methane production and utilization, it is estimated that over 8 million metric tons of methane were produced from degasification systems in the primary foreign coal producing countries and that nearly 2 million metric tons, over 20 percent, was utilized. The highest methane emission utilization rates are in the mines of Poland, West Germany, and the United Kingdom.

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[40] Curl, S.J., 1978.

EXHIBIT 3-10

ESTIMATED WORLD METHANE EMISSIONS FROM COAL MINING

Primary Coal Producing Countries	Estimated Methane Emissions (Million metric tons)		
	Underground	**Surface**	**Total**
China	16.0	0.1	16.1
U.S.S.R.	7.7	0.6	8.3
United States	6.1	0.9	7.0
East Germany	0	0.5	0.5
Poland	3.3	0.1	3.4
Australia	0.9	0.2	1.1
West Germany	1.4	0.2	1.6
India	1.5	0.2	1.7
South Africa	2.0	0.1	2.1
Czechoslovakia	0.4	0.2	0.6
United Kingdom	1.5	≤0.1	1.6
Subtotal	40.8	3.2	44.0
(Range)	(28.3 - 55.2)	(2.2 - 4.3)	(30.5 - 59.5)
Secondary Coal Producing Countries			
North Korea	0.7	<0.1	0.7
South Korea	0.4	0	0.4
Spain	0.2	<0.1	0.3
France	0.2	<0.1	0.2
Japan	0.2	0	0.2
Canada	<0.1	0.1	0.1
Turkey	0.1	<0.1	0.1
Brazil	0.1	0	0.1
Mexico	0.1	0	0.1
Yugoslavia	<0.1	0.1	0.1
Belgium	0.1	0	0.1
Zimbabwe	0.1	0	0.1
Colombia	≤0.1	≤0.1	≤0.1
Subtotal	2.3	0.3	2.6
(Range)	(1.6 - 3.1)	(0.2 - 0.4)	(1.8 - 3.5)
Other Coal Producing Countries	0.6	0.2	0.8
(Range)	(0.4 - 0.8)	(0.1 - 0.3)	(0.6 - 1.1)
TOTAL ESTIMATED METHANE EMISSIONS FROM COAL MINING (RANGE)	43.7 (30.3 - 59.1)	3.7 (2.6 - 5.0)	47.4 (32.8 - 64.1)

Note: One million metric tons of methane (10^{12}g) equals 1.49 billion cubic meters of methane (52.6 billion cubic feet).

A number of secondary coal producing countries are also of interest because although they represented 23 percent of foreign mined coal tonnage in 1987, they accounted for only an estimated 5 percent (2 to 3 million metric tons) of worldwide methane emissions. For the most part, methane emissions are low in these countries because almost 75 percent of the coal was produced from surface mines which have low methane emission rates. By comparison, surface mining in the primary coal producing countries accounted for less than half of the total production in 1987.

Methane emissions associated with coal mining in some of these secondary coal producing countries could increase in the future, however. Many of the secondary coal producers are developing nations that rely heavily on their coal resources for energy and export revenues. As shallow coal reserves are exhausted, these countries will begin developing their deeper coal resources, which will lead to increases in future methane emissions.

The remaining coal producing countries of the world account for less than 2 percent (0.6 to 1 million metric tons) of the estimated worldwide methane emissions from coal mining and only 5 percent of total coal production.[41] As with the secondary coal producing countries, surface mined coal accounts for 82 percent of the total coal produced in these countries. Future coal production in these countries is also expected to be from the deeper coal reserves, however, as shallow seams are depleted, which could result in increased methane emissions in the future.

Global Estimates of Methane Emissions from Coal Mining

As shown in Exhibit 3-10, coal mining and utilization operations throughout the world emitted an estimated 33 to 64 million metric tons of methane to the atmosphere in 1987.[42]

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[41] The remaining coal producing countries include: Afghanistan, Albania, Argentina, Austria, Botswana, Bulgaria, Burma, Chile, Ecuador, Egypt, Greece, Hungary, Indonesia, Iran, Ireland, Italy, Mongolia, Morocco, Mozambique, New Zealand, Nigeria, Pakistan, Peru, Philippines, Portugal, Romania, Swaziland, Taiwan, Thailand, Venezuela, Vietnam, Zaire, and Zambia.

[42] Since one million metric tons of methane has a volume of 1.49×10^9 cubic meters at standard temperature and pressure, it is estimated that between 44 and 96 billion cubic meters (2 to 3 trillion cubic feet) of methane was vented to the atmosphere as a result of coal mining in 1987.

China was the single largest source of methane emissions from coal mining related activities, contributing an estimated 11 to 22 million metric tons, or just under 34 percent of the total worldwide emissions. The Soviet Union was the second largest source of methane from coal mining, with estimated emissions of 6 to 11 million metric tons, or almost 18 percent of the total. The United States was third, accounting for 15 percent (5 to 9 million metric tons) of estimated emissions. Together, these three countries were responsible for two-thirds (an estimated 22 to 42 million metric tons) of the total coal-related methane emissions.

In the future, it is expected that methane emissions associated with coal mining will increase. Worldwide coal production is expected to increase, especially in developing nations. During the 1980's, coal production grew by 2.7 percent per year, and this rate of growth is expected to continue in the future as energy consumption increases in many developing countries. This increase in production is expected to result in the mining of deeper coals which tend to have higher methane contents and higher associated methane emissions.

A very approximate estimate of how much methane emissions from coal mining might increase is shown in Exhibit 3-11. As the exhibit shows, by the year 2000 methane emissions from coal mining could range from 72 to 81 million metric tons.

The methane emissions estimates developed in this study are compared to other estimates in Exhibit 3-12. As the exhibit shows, previous estimates have ranged from 8 to 45 million metric tons per year, while the present study estimates emissions of 33 to 64 million metric tons per year. The variation between estimates is largely attributable to differences in methodology and input data, especially in terms of coal production, coal type and estimated average methane emissions from the mined coal. Some of the major studies are described briefly below and compared with the present study.

EXHIBIT 3-11

ESTIMATED GLOBAL FUTURE METHANE EMISSIONS FROM COAL MINING AND UTILIZATION

	Estimated Coal Mining-Related Methane Emissions, Million Metric Tons
• **Estimated Methane Emissions in 1987**	47
• **Additional Methane Emissions in 2000 Associated with an Increase in Global Coal Production** (@ 2.68% per year)*	19
• **Additional Methane Emissions in 2000 Associated with an Increase in Mine Depth** (from current 53% underground to 60 to 70% underground)**	6 to 15
Total	72 to 81

* This assumes that world coal production grows by 2.7 percent annually between 1990 and 2000, as assumed in IEA Coal Production 1987, which may be conservative in certain countries. The Soviet Union and China, for example, are planning to expand coal production at faster rates.

** Increases in mine depth estimated from rates of change in mining depth since 1960 as reported by IEA Annual Coal Production reports.

Koyama is credited with preparing the first estimate of methane emissions from coal mining, in which he estimated that 20 million metric tons of methane was liberated annually as a result of mining.[43] His estimate was based on coal production data from 1960, however, and coal production has increased by more than 75 percent between 1960 and 1987. In addition, it appears that this estimate only included methane emissions from hard coal production.[44] Given these two factors, Koyama's estimate likely underestimates current methane emissions from coal mining.

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43 Koyama, T., 1964.

44 World coal production is generally divided between hard coal (bituminous and anthracite) and brown coal (sub-bituminous and lignite). For this study, it was assumed that hard coal production represents underground mines and brown coal production represents surface mines.

EXHIBIT 3-12

COMPARISON OF COAL MINING-RELATED EMISSION ESTIMATES

	Total Methane Emissions (million metric tons/year)	Average Coal Methane Content (m^3/metric ton)	Type of Coal Included In Emissions Estimate	Year of Coal Production Data
Koyama (1964)	20	17.7	Hard Coal only[1]	1960
Hitchcock and Wechsler (1972)	8 - 28	5 - 17.7	Hard and Brown Coal	1967
Ehhalt (1974)	8 - 28	5 - 17.7	Hard and Brown Coal	1967
Seiler (1984)	30	17.7	Hard Coal only[1]	1975
Crutzen (1987)	34	18 - 19	Hard Coal only[1]	N/A[2]
Seeliger and Zimmermeyer (1989)	24	14	Hard Coal only[1]	1987
Cicerone and Oremland (1989)	25 - 45	N/A[2]	Hard Coal Only[1]	N/A[2]
Present Study	33 - 64	2.5 Surface 27.1 Underground	Hard and Brown Coal	1987

[1] Report does not specify coal type used in estimating methane emissions. Coal tonnage values approximately match hard coal production only.

[2] Not Available -- This parameter was not specified in the report.

Another estimate of methane emissions from coal mining was included in a 1972 study by Hitchcock and Wechsler.[45] This study used Koyama's assessment of methane contents of coal and coal production data from 1967. Unlike the Koyama study, the Hitchcock and Wechsler study included methane emissions from both hard coal and brown coal production. In addition, the authors established a range of 5 to 17.7 cubic meters of methane emitted per ton of coal mined. Given the lower total coal production, however, the Hitchcock and Wechsler study estimate of 8 to 28 million metric tons of methane emissions from coal mining underestimates current emission levels.

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[45] Hitchcock, D.R., and Wechsler, A.E., 1972.

The Hitchcock and Wechsler study was followed in 1974 by another study on the atmospheric cycle of methane prepared by Ehhalt.[46] In Ehhalt's study, the estimate of methane emissions from coal mining was based directly on the work of Hitchcock and Wechsler and thus ranged from 8 to 28 million metric tons.

In 1984, Seiler published a study that estimated methane emissions form coal mining at 30 million metric tons.[47] Seiler used the same ratio of methane emissions per ton of mined coal as Koyama had established, but he used hard coal production data from 1975.

Crutzen estimated methane emissions at 34 million metric tons in his 1987 study.[48] This estimate was based on an estimated emission rate of 18 to 19 cubic meters of methane per ton of coal mined. It is not clear which year of coal production data was used for this estimate, but early 1980's hard coal production data appears to have been used.

More recently, Cicerone and Oremland published revised methane emission estimates of 25 to 45 million metric tons from coal mining.[49] Cicerone and Oremland did not develop new data or a new methodology, but instead cited previous studies by Seiler and Ehhalt. Thus, their estimates are also based on the work of Koyama and, like the previous studies, include only hard coal production data. It is not clear from their report what level of methane emissions per ton of mined coal was assumed or what year's coal production data was used.

The most recent study reviewed herein was prepared by Seeliger and Zimmermeyer, who estimated that global methane emissions from coal mining were 24 million metric tons in 1987.[50] This estimate was based on hard coal production data from 1987 and assumed a methane emission rate of 14 cubic meters per ton of coal mined. The combination of a low assumed emission rate and only hard coal production data result in a significantly lower estimate

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[46] Ehhalt, D.H., 1974.

[47] Seiler, W., 1984.

[48] Crutzen, P.J., 1987.

[49] Cicerone, R.S., and Oremland, R.S., 1988.

[50] Seeliger, W., and Zimmermeyer, G., 1989.

than contained in the present study.

The present study estimates that methane emissions from coal mining could range from 33 to 64 million metric tons, which is higher than previous estimates. There are three main reasons for the higher estimates:

- Estimates use more recent coal production data, which reflects higher total coal tonnage mined.
- Estimates include both underground and surface mining. While it has been shown that the methane content of surface mined coal is lower than underground mined coal, the methane emissions associated with surface coal mining could be significant because total surface coal production represents approximately 25 percent of total world coal production. Estimated methane emissions from surface mining range from 3 to 5 million metric tons in this study, or account for about 8 percent of total emissions.
- Estimates include methane emissions from coal mining, coal mine degasification systems, and post-mining coal utilization. Emissions associated with degasification systems and coal utilization are significant, accounting for approximately 22 percent of total emissions.

Study Uncertainties

As has been previously indicated, a number of important assumptions were made in developing these estimates of global methane emissions associated with coal mining and utilization. As a result, the estimates should be considered approximate, and the uncertainties associated with them are reflected in the ranges presented. Some of the major uncertainties and their potential impacts on the emissions estimates are presented below.

Uncertainties in Data

Coal Production Data. As the discussion of methodology indicated, coal production data is one of the foundations of any estimate of methane emissions from coal mining. In the United States, coal production data are collected by both state and federal agencies and accurate data on production levels by state and method (surface or underground) can be readily obtained. In many foreign countries, however, data are less available and their accuracy is less certain. In addition, in some countries, data on coal production by type (hard or brown) is available but the production method (surface or underground) is not. In these cases, it was assumed that hard coal production represented underground mines and brown coal production represented surface mines.

Naturally, these data limitations introduce uncertainties in the analysis. Without more detailed information on the specific countries, however, it is impossible to determine the extent to which these uncertainties affect the estimates herein. Where possible, foreign countries were contacted directly for information on their coal production and this information was incorporated. A more detailed examination of each country's coal production should be undertaken as part of future research efforts.

Methane Content of Coal. The methane content of mined coal is the second critical type of data. As with coal production data, good information exists for methane content in the United States because of the work of the USBM, DOE, GRI, and others. In other countries, however, these data are often unavailable. Such data are necessary on a country-by-country basis to develop more accurate country-specific estimates of methane emissions from coal mining.

Uncertainties in Methodology

Mining Emissions Equation. The relationship between the in-situ methane content of the mined coal and the methane emissions associated with mining as reflected in the "mining emissions equation" is not well defined. The most accurate approach toward estimating these emissions would be to develop an emissions factor for every coal mine. Such an approach would be prohibitively expensive and data-intensive, however, given the number of mines worldwide. Instead of taking this approach, a methane emissions equation was developed statistically in this study. This equation was based on measurements at 59 United States coal mines. The uncertainty in the equation was estimated to be $\pm$ 23 percent, based on the results of the regression analysis, and this uncertainty estimate was used to develop a range of emission estimates for each state, and for the United States average methane content estimates.

Applying United States Data to Other Countries. The data required to develop a methane emissions equation was unavailable for foreign countries, as was the in-situ methane content data necessary to apply the mining emissions equation developed for the United States. Thus, the estimated average methane emissions per ton of coal mined were determined for the United States and applied to other coal producing countries. This assumption introduces significant uncertainties into the results because it assumes that the mixture of coal mined in each country resembles the mixture of United States coals (in terms of in-situ methane content), that the mining methods used (underground longwall or room-and-pillar and surface) and the proportion of each are similar, and that degasification technologies are applied to the same extent. Since these and other factors vary, the accuracy of the assumption is uncertain. In the absence of detailed country-specific data, however, it is difficult to produce international estimates without making such assumptions. To reflect the uncertainty inherent in this assumption, an additional range of $\pm$ 10 percent was applied to the range of average methane emissions estimated for the United States

Uncertainties in Future Emissions Estimates. Finally, estimates of future emissions from coal mining and utilization are highly uncertain and depend on factors such as future coal production levels and the extent to which deeper coal mines are developed. For utmost accuracy, such estimates should be determined on a country-specific basis, taking into account forecasted growth in coal production, current and projected mining methods, and methane content of future coal reserves. Such estimates were not prepared as part of this study, and hence the estimates contained herein are approximate. The trend toward higher methane emissions associated with coal mining is more certain, however, because of the established relationship between methane emissions and coal productions levels.

CHAPTER IV

Technical and Economic Evaluation of Methane Control Techniques

There are several options available for using the methane currently vented to the atmosphere from coal mining operations. To date, these options have not been extensively exploited in the United States, largely because of a variety of economic, institutional, and legal barriers. While some mining operations in other countries, particularly in Europe and Australia, collect and use the methane released during coal mining, this practice is still not widespread.

This chapter examines the technical and economic issues related to the application of methane recovery and has two sections. The first section describes some of the major options available for methane utilization and the major barriers currently precluding the application of the recovery technologies in the United States. The second section provides a detailed economic analysis of one utilization option -- sale to a natural gas pipeline.

Options for Methane Utilization

Control of methane has long been essential in underground coal mines for safety reasons. As discussed in Chapter 1 of this report, there has been significant research devoted to the subject of methane control. The main technique for controlling methane remains ventilating the underground mine workings. However, other supplemental methane control techniques have been practiced for many years throughout the United States and around the world.

Modern methane control techniques produce gasses containing varying concentrations of methane. Three primary types of gasses are produced by methane control techniques. The first gas - Type 1 - is produced almost exclusively by a mine's ventilation system and contains low concentrations of methane in air (generally less than 1 percent). The second gas - Type 2 -- is produced by various degasification or methane drainage practices, and is an air-methane mixture with methane concentrations generally varying from 30 to 90 percent. The final gas - Type 3 - is produced from certain degasification systems and generally contains 90 to 100 percent methane.

Currently, most of the methane produced by mining operations is vented to the atmosphere. If this methane were used instead of vented, reduced emissions to the atmosphere would be realized. The decision to use recovered methane is site-specific and depends on the type of gas recovered. The principal uses for different gas types are described below.

Type 1 Gas - Type 1 gas is produced as a result of the mine's ventilation system and is essentially air containing small quantities (generally less than 1 percent) of methane. This gas is produced in large quantities by mines, often exceeding 40 million cubic meters (1.4 billion cubic feet) per day and has always been vented directly into the atmosphere.[51] Utilization options for this Type 1 gas are limited, chiefly because of the low concentration of methane and the large volume of gas. Two utilization schemes have been proposed for this gas: the first involves removing the methane molecules from the gas stream, which results in a higher grade energy source (up to 100 percent methane) and the second method uses the Type 1 gas as primary input air for a combustion process utilizing oil, natural gas, or coal.

The removal of methane from the Type 1 gas can technically be achieved using various molecular membranes or sieves.[52] However, methane-air mixtures are generally difficult to separate due to the similar separation characteristics of methane and nitrogen. In addition, the systems usually require high inlet pressures, necessitating the compression of the Type 1 gas. The power cost of such systems make them uneconomic at current gas prices. Moreover, the process produces CO_2 as a byproduct, which is also a greenhouse gas.

Alternatively, the Type 1 gas could be injected as air for a combustion process burning coal, natural gas, or oil, such as those used for electric power generation, steel manufacturing, or kiln heating. While this system readily consumes the methane in the combustion chamber,

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[51] Grau, R.H., 1987.

[52] Garcia, F. and Cervik, J., 1988.

the costs associated with transporting the large quantities of Type 1 gas any significant distance would be very high. Thus, this process would only be suitable when the combustion process plant was located near the mine's ventilation system discharge point. Given the amount of methane released to the atmosphere from ventilation systems, additional research on this utilization option should be undertaken.

Type 2 Gas - Type 2 gas is produced by methane control techniques that supplement a mine's normal ventilation system. These techniques include 1) horizontal and cross measure boreholes to pre-drain the methane in advance of mining, 2) cross measure boreholes and gob (goaf) wells to drain the methane from sections of the mine where mining has been completed, and 3) miscellaneous drainage systems, such as vacuum systems on sealed mine areas. The methane produced by these processes can have varying methane concentrations, depending upon such factors as the operating conditions of the system, the amount of air leakage into the system, and local geologic and engineering conditions in the mine.

Utilization of the Type 2 gas is currently practiced at some mining operations. In some operations, the methane is utilized as a low calorific value gas for industrial and home heating purposes. In other cases the Type 2 gas is used as fuel in gas turbines to generate electric power. The uses of for this gas are numerous and the higher calorific value, as compared to Type 1 gas, often justifies its compression and transportation.

Type 3 Gas - Type 3 gas represents high quality, pipeline-grade natural gas and is produced by 1) degasification systems similar to those producing Type 2 gas and 2) by degasification systems that employ vertical wells drilled in advance of active mining operations. Some mines with horizontal, cross measure, or gob wells have been successful in controlling the operating conditions of these systems and have the required geologic and reservoir conditions that enable them to produce pipeline-grade Type 3 gas. It must be emphasized, however, that the optimum operating conditions for producing Type 3 gas may not be the optimum condition for mine degasification. In these situations, mine safety cannot be compromised by the inefficient operation of a degasification system for the purpose of producing Type 3 gas.

The primary method of producing Type 3 gas is through the use of vertical wells drilled in advance of the mine workings. This degasification system has the advantage of pre-draining a gas that has not been contaminated by the mine air. The resulting Type 3 gas is usually of pipeline grade, often requiring only dehydration and compression for utilization. Because of the high calorific value, Type 3 gas can be utilized by many processes. Often it is compressed and injected into natural gas pipelines for distribution to commercial and residential users. In addition, it can be used for all of the same processes described above for Type 2 gas, such as electric power generation or industrial heating.

In addition to the constraints placed on utilization by the various types of gas produced, there remain, at least in the United States, certain legal and regulatory constraints that also affect utilization of methane produced by coal mining. Unresolved issues of ownership of the methane have negatively impacted the utilization of the produced methane (primarily in the form of Type 2 and 3 gasses). Further, the operation of mine ventilation and degasification systems is strictly controlled by federal, state, and local regulatory bodies, which can affect the type and quantity of produced gas. Detailed discussion of these constraints is beyond the scope of this report, but further information can be found in other reports.[53]

Economic Evaluation of Methane Control Techniques

As described in the previous section, there are many uses for methane that is currently vented into the atmosphere by the mining process. In many cases, however, the economic attractiveness of these utilization options is not well defined. This section explains the methodology developed to evaluate the economics of one utilization option - the sale of Type 3 methane produced by degasification systems into natural gas pipelines in the United States

The gas contained in coal is usually very similar to natural gas produced from conventional gas reservoirs (sandstones, limestones, etc.) in that both generally contain 90 to 99 percent methane. Thus, this methane, can be sold for industrial or consumer use as natural

[53] See for example, Counts, R.A., 1989; Eastern Mineral Law Foundation, 1988.

gas if it is undiluted by mine air. The question addressed in this section is -- under what economic conditions and with which of the degasification techniques is it possible to recover a high percentage of this methane economically? This section of the report examines three degasification methods in terms of their methane recovery efficiency and their costs. For mines that can sell recovered methane as natural gas, the study also examines the economic costs and benefits of these degasification methods.

Methodology

The evaluation of control techniques for mining-related methane emissions followed a four-step approach. This technical approach, including the data used and the models employed, is summarized below. For more detailed information on the methodology and results, see Appendix C.

1. **Selection of Underground Mining Scenarios.** Most U.S. underground coal mines are located in the eastern United States. These eastern mines accounted for over 70 percent of all United States underground coal mines and produced 240 million tons of coal in 1987. The Warrior Basin and the Northern Appalachian Basin are two of the more active eastern United States coal basins and were chosen as test settings for examining the economics of pipeline-grade natural gas production using alternative methane recovery techniques.

The Mary Lee coal seam of the Warrior Basin, Alabama was selected to represent deep, longwall mining operations that generate large quantities of methane emissions during mining. Grau reports that 11 of the 15 highest methane emitting coal mines in the United States were deep, longwall mines in Alabama and Virginia.[54] The mining scenario modeled for the Warrior Basin is a longwall mine in the gassy Mary Lee coal seam at a depth of 625 meters. The selected coal and gas properties for the Warrior Basin, shown in Exhibit 4-1, reflect the geologic conditions (i.e., mine depths, seam thicknesses, cleat spacings) currently encountered by some active mining operations in this basin.

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[54] Grau, R.H., 1987.

EXHIBIT 4-1

SUMMARY COAL AND GAS PROPERTIES FOR PRODUCTION MODELING
WARRIOR COAL BASIN

Coal/Gas Property	Coal Seam Identification		
	Pratt	Mary Lee	Black Creek
Depth Below Surface(m)	396	625	663
Net Coal Seam Thickness (m)	4.3	2.65	2.87
Cleat Permeability (md)	20.4	7.30	6.1
Cleat Spacing (cm)	0.51	0.51	0.51
Matrix Porosity (%)	3.0	3.0	3.0
Initial Seam Pressure (kPa)	3,365	5,309	5,633
Seam Temperature (^{o}K)	259	303	305
Initial Cleat Water Saturation (%)	100	100	100
Initial Matrix Gas Content (m^3/gas per m^3/coal)	15.6	20.4	20.9
Langmuir Volume (m^3/gas per m^3/coal)	18.8	24.4	25.2
Langmuir Pressure (kPa)	673	1,062	1,127
Desorption Pressure (kPa)	3,365	5,309	5,633
Desorption Time (Days)	10	10	10
Gas Gravity (Air = 1.0)	0.60	0.60	0.60

Good geologic and reservoir data exist for the coal seams of this basin because of the active coalbed methane production industry and the new mine degasification efforts currently underway.[55]

The Pittsburgh coal seam of the Northern Appalachian Basin was selected as being representative of the less gassy, moderate depth coal mines. Exhibit 4-2 presents representative geologic and reservoir parameters for the Pittsburgh coal. Because this coal seam is one of the most actively underground mined coal seam in the United States, a considerable amount of research and data collection has been conducted by the USBM and DOE on this coal seam.[56]

2. Selection of Degasification Techniques. The primary technique for controlling methane emissions in United States coal mines is the use of large volume air circulation to dilute and sweep the methane out of the mine workings. Because ventilation leads to low concentrations of methane within the vented air/methane mix, this control technique limits the options available for utilization of the emitted methane. To produce methane in concentrations that are acceptable for use as natural gas, the methane must be captured by specific degasification methods. Three primary degasification methods are currently used in the United States to capture methane before it is released into mine workings: pre-drainage vertical wells, vertical gob wells, and horizontal wells. Data for capital costs, operating costs, and expected gas production rates and quantities were assembled from numerous sources for each of the techniques.[57] In addition to evaluating these three primary degasification techniques separately, the combination system of pre-drainage vertical wells and vertical gob wells was evaluated. These four methane control techniques are discussed below.

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[55] See for example, Diamond, W.P., Bodden, W.R., Zuber, M.D., and Schraufnagel, R.A., 1989; Dixon, C.A., 1989; McFall, K.S., Wicks, D.E., and Kuuskraa, V.A., 1986; and McElhiney, J.E., Koenig, R.A., and Schraufnagel, R.A., 1989.

[56] See for example, Diamond, W.P., Lascola, J.C., and Hyman, D.M., 1986; Mroz, T.H., Ryan, J.G., and Byrer, C.W., 1983; and Deul, M. and Kim, A.G., 1988.

[57] Kuuskraa, V.A., Boyer, C.M., and McBane, R.A., 1989; Pothini, B.R., 1986; and Grau, R.H. and Baker, E., 1987.

EXHIBIT 4-2

SUMMARY COAL AND GAS PROPERTIES FOR PRODUCTION MODELING
NORTHERN APPALACHIAN COAL BASIN

	Coal Seam Identification				
Coal/Gas Property	Waynesburg	Sewickley	Redstone	Pittsburgh Rider	Pittsburgh
Depth Below Surface(m)	107	168	213	243	244
Net Coal Seam Thickness (m)	1.22	0.91	0.76	0.30	2.44
Cleat Permeability (md)	50	39	32	30	30
Cleat Spacing (cm)	0.64	0.64	0.64	0.65	0.64
Matrix Porosity (%)	2.0	2.0	2.0	2.0	2.0
Initial Seam Pressure (kPa)	772	1,213	1,544	1,813	1,813
Seam Temperature (^{o}K)	288	289	290	291	291
Initial Cleat Water Saturation (%)	100	100	100	100	100
Initial Matrix Gas Content (m^3/gas per m^3/coal)	4.4	6.0	6.0	7.2	7.2
Langmuir Volume (m^3/gas per m^3/coal)	16.0	16.0	16.0	16.0	16.0
Langmuir Pressure (kPa)	1,896	1,896	1,896	1,896	1,896
Desorption Pressure (kPa)	772	1,213	1,544	1,813	1,813
Desorption Time (Days)	100	100	100	100	100
Gas Gravity (Air = 1.0)	0.65	0.65	0.65	0.65	0.65

Pre-drainage Vertical Wells - Pre-drainage vertical wells are similar to conventional oil and gas wells which are drilled and operated from the surface. The wells are hydraulically stimulated with large volumes of fluid (up to 380,000 liters) mixed with 22,500 - 27,000 kg of sand under high pressure (up to 20,000 kPa). In this study, the wells were assumed to produce methane from the mined coal seam as well as the other significant coal seams above or below the main seam. In the Warrior Basin, the coal seams being multiply-completed by vertical wells are the Pratt, the Mary Lee (the mined coal seam), and the Black Creek. In the Northern Appalachian Basin, producing coal seams include the Waynesburg, the Sewickley, the Redstone, the Pittsburgh Rider, and the Pittsburgh (the mined coal seam).

Vertical Gob Wells - Vertical gob wells produce gas from the collapsed zone created after a longwall panel has been mined-out. Following the collapse of the coal seam roof, the subsequent fracturing of the surrounding rock and coal strata allows the gob wells to produce large quantities of methane in a short-period of time. After the initial surge of methane, the quality of the gas may decline as it becomes mixed with air from the mine workings. However, in some cases, the methane concentrations have been kept at 95 to 99 percent for long periods of time (often over one year).[58] For this evaluation, it was assumed that the modeled gob wells could produce gas at pipeline quality for one year.

In-Mine Horizontal Wells - In-mine horizontal wells are drilled from within the active mine workings into the unmined longwall panel. These wells, while reasonably effective in recovering methane from the longwall panel in the main coal seam, are not able to capture methane emitted from the overlying and/or underlying rock and coal strata. Also, because the mine workings need to be well developed before the horizontal wells can be drilled, a significant amount of methane is vented before these wells are fully installed. Horizontal well life was assumed to be 6 months in this analysis, which is consistent with reported well lives from published sources.[59]

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[58] Dixon, C.A., 1989; Layne, A.W., Siriwardane, H.J., and Byrer, C.W., 1988.

[59] Grau, R.H., and Baker, E., 1987; Pothini, B.R., 1986.

3. Modeling of Methane Production. Methane production for these degasification techniques was modeled using **COMET-PC 3D**, a finite-difference numerical production simulator developed by ICF Resources with support from the Gas Research Institute.[60] This simulation model accounts for the storage and release of the adsorbed methane, estimates the diffusion-based flow of the methane through the coal matrix, and calculates the two-phase flow of gas and water through the coal cleat system. The specific coal and gas properties used to model methane production from each of the coal mining regions were presented in Exhibits 4-1 and 4-2. It is important to remember that these reservoir properties represent a hypothetical area within the two mining regions, and should not be considered representative of either specific mines or an average mine in these areas.

The longwall mining operations were modeled using a standard unit of comparison, a longwall panel. Longwall panels in United States mines may range up to 3,000 meters in length and will vary from 90 to 300 meters in width. For this study, a longwall panel 200 meters wide by 1,540 meters long, with a 20 meter band of entry ways and pillars surrounding the longwall panel, and incorporating a gob area defined by the overlying and underlying coal seams presented in Exhibits 4-1 and 4-2, was used as the standard unit of comparison (38.6 hectares or 95.5 acres). Although a longwall panel was selected as the unit of evaluation, the results of this study can generally be applied to a similar sized area in a room and pillar mine, especially when considering the pre-drainage effects of vertical wells and horizontal boreholes.

4. Economic Analysis. The first step in the economic analysis of each degasification system was to estimate the capital and operating costs for installing the system. Then, the costs and revenues were financially integrated to establish conditions under which the capture and sale of the methane could be a profitable venture for the mine operator.

Capital and Operating Costs - The following Exhibits 4-3, 4-4, and 4-5, provide the main cost components involved in the selected mine degasification program, as discussed further below. These costs were compiled based on:

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60 Kuuskraa, V.A., Boyer, C.M., and McBane, R.A., 1989.

EXHIBIT 4-3

CAPITAL AND OPERATING COSTS
VERTICAL WELLS IN ADVANCE OF MINING

Capital Cost Category	Cost (1988 $) Warrior Coal Basin	Cost (1988 $) Northern Appalachian Coal Basin
Surface Site Development and Preparation, Vertical Borehole	14,965/well	12,185/well
Drill, Complete, and Equip Well	51,000/well	32,000/well
Surface Production Equipment and Installation	20,250/well	14,000/well
Water Disposal Equipment	5,000/well	5,000/well
Hydraulic Fracture Treatment	18,500/well	18,500/well
Compressor	190/Mcf/d*	190/Mcf/d*
Abandon Well	2,000/well	2,000/well
Annual Operating Cost Category		
Normal Operations and Maintenance	6,635/well	4,950/well
Water Disposal	0.25/Barrel**	0.25/Barrel
Compressor Operation	0.06/Mcf	0.06/Mcf

* Mcf/d - 1,000 cubic feet per day (28.3 cubic meters per day).
** Barrel - 42 United States gallons (160 liters).

EXHIBIT 4-4

CAPITAL AND OPERATING COSTS
IN-MINE HORIZONTAL BOREHOLES IN ADVANCE OF MINING

	Cost (1988 $)	
Capital Cost Category	Warrior Coal Basin	Northern Appalachian Coal Basin
Surface Site Development and Preparation, Vertical Borehole*	3,000/panel	2,500/panel
Drill, Complete, and Equip Vertical Borehole	10,125/panel	6,400/panel
Surface Production Equipment and Installation	4,265/panel	3,010/panel
Horizontal Well Drilling Equipment	295/panel	295/panel
In-Mine Methane Drainage Equipment and Installation	1,530/panel	1,020/panel
Drill, Complete, and Equip Horizontal Wells	4,650/panel	4,515/panel
Abandon Vertical Borehole	400/panel	400/panel
Compressor	190/Mcf/d**	190/Mcf/d
Annual Operating Cost Category		
Normal Operations and Maintenance	1,330/panel	990/panel
Compressor Operation	0.06/Mcf	0.06/Mcf

* Costs assume one vertical borehole serves five longwall panels or mine blocks.
** Mcf/d - 1,000 cubic feet per day (28.3 cubic meters per day).

EXHIBIT 4-5

CAPITAL AND OPERATING COSTS
VERTICAL GOB WELLS DURING MINING

	Cost (1988 $)	
Capital Cost Category	Warrior Coal Basin	Northern Appalachian Coal Basin
Surface Site Development and Preparation	14,965/well	12,185/well
Drill, Complete, and Equip Well	76,125/well	48,000/well
Surface Production Equipment and Installation	21,325/well	15,050/well
Abandon Well	2,000/well	2,000/well
Compressor	190/Mcf/d*	190/Mcf/d
Annual Operating Cost Category		
Normal Operations and Maintenance	6,635/well	4,950/well
Compressor Operation	0.06/Mcf	0.06/Mcf

* Mcf/d - 1,000 cubic feet per day (28.3 cubic meters per day).

(1) Surface Site Development and Preparation. This category includes the costs for surface rights, surveying, site preparation, road construction, and installation of electric power.

(2) Drill, Complete, and Equip Vertical Wells. This cost category includes the costs for the drilling and crew, well tubing and casing, and well cementing. It also includes the cost of wellhead and downhole equipment such as pumps and motors. The variations in vertical well costs reflect differences in well depths and any differences in the well equipment and completion techniques required by each of the methane control techniques.

(3) Surface Production Equipment and Installation. Included in these costs are low- and high-pressure gas separators, gas dehydration equipment, metering and pressure measurement devices, and gathering lines for delivering the gas to a distribution pipeline. Also, flame arrestors and lightening protectors are included.

(4) Water Disposal Equipment. Because water production often accompanies pre-mining gas recovery from coal seams, capital costs for water handling and disposal, such as for tanks, gathering lines and disposal ponds are included.

(5) Hydraulic Fracture Treatment. These costs include manpower, materials, and service costs for performing a single hydraulic stimulation of the target coal seam.

(6) Compressor. These costs are the pro-rated share of a compressor station servicing a group of wells or boreholes.

(7) Abandon Well. Because the various well types have finite operating lives, this category represents the cost of abandoning the well or borehole, as often required by state or federal regulations.

(8) Horizontal Well Drilling Equipment. These costs represent the pro-rated share of the capital cost associated with the purchase of the in-mine drilling equipment.

(9) In-Mine Methane Drainage Equipment and Installation. These costs are associated with the equipment placed in the mine to operate the horizontal boreholes.

(10) Drill, Complete, and Equip Horizontal Wells. This cost category represents labor and material costs required for installing the horizontal boreholes.

(11) Normal Operations and Maintenance. These costs include the manpower, materials, and power costs for the operation, maintenance, and administration of the producing wells.

(12) Water Disposal. A cost of $0.25 per barrel is used to account for the handling and disposal of the produced water based on the field experience of large scale oil field operations. Where the water meets surface discharge requirements, this cost could be considerably lower. Alternatively, where the water needs to be trucked off-site for disposal, the costs may be several times higher.

(13) Compressor Operation. Because the methane produced from degasification operations is generally at very low pressures, (generally less than 25 psi), the gas pressure must be boosted by compression. A cost of $0.06 per Mcf for operations and power is used, based on current costs in the Warrior Basin.

Financial Analysis - In this study, the economic viability or benefit of methane emissions control is established by calculating the difference between the revenues generated from the sale of the produced gas and the costs incurred in producing and marketing the gas.[61] As previously mentioned, all underground coal mines require some form of methane emission control. This is primarily through the use of mine ventilation systems. However, some mines currently employ methane emission control techniques (vertical, gob, and horizontal wells) to supplement the existing ventilation system. For those mines that have already installed methane control systems and where the methane produced is of pipeline quality, the costs incurred in producing and capturing the methane from these systems would only be the incremental costs (above the already installed system cost) required to collect and transmit the produced gas.

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[61] Kuuskraa, V.A., Boyer, C.M., and McBane, R.A., 1989.

These costs would include the compression facilities, gas collection system, and production control systems. Therefore, this analysis, which assumes total investment cost (not incremental), could be conservative when considering mines with existing methane control systems, assuming pipeline quality gas can be produced by the mine's degasification systems.

To provide a present value basis for this calculation, the resulting profits or losses are discounted using a 10% discount rate. The following equations are used:

$$\text{Gas Revenues} = \text{Gas Production (Mcf)} \times \text{Selling Price (\$/Mcf)}$$

$$\text{NPV Profits/Losses (\$/Mcf)} = \text{NPV of } \frac{\text{(Gas Revenues (\$) - Investment and Operating Costs (\$))}}{\text{Mcf of Methane Produced*}}$$

* Estimated methane recovery from standard longwall panel.

Revenues are calculated at wellhead gas selling prices ranging from $0.00/Mcf to $3.00/Mcf. The zero gas selling price case assumes that no market exists for selling the gas (or that the produced gas is not of pipeline quality) and that the methane is flared or vented. A $2.00 per Mcf gas selling price (at the wellhead) reflects the near-term outlook for gas prices in the Warrior and Appalachian Basins. The $3.00 per Mcf wellhead selling price represents a projected gas price for the mid to late 1990's.

The economic effect of methane control on the mining operation is presented in terms of the total net present value (NPV) profit (loss) per Mcf of methane produced. As a basis for comparing the financial impact of methane control, the current average coal prices (mine mouth) in the eastern United States range from $21 to $24 per ton.

Preliminary Economic Analysis Findings and Results

The analysis indicates that with good technology, substantial quantities of methane can be recovered during mining operations and that, in certain cases, the mining company could realize substantial economic benefits. This section presents the findings and results from the technical and economic analysis, first for a gassy, deep coal of the Warrior Basin and then for the shallower coal of the Northern Appalachian Basin. Detailed results of the economic evaluation can be found in Appendix C.

Significant reductions in methane emissions from coal mining can be achieved in the two hypothetical study areas of Warrior and Northern Appalachian Basins using degasification ahead of or in conjunction with mining. From the analysis performed, highly efficient methane recovery can be obtained by using vertical wells installed ten years in advance of mining, gob wells draining methane from the fractured gob area after mining, or a combination of the vertical/gob well system. Horizontal wells, while effective for achieving short-term reductions in methane emissions during mining, are the least efficient technique. This is because horizontal boreholes only drain methane from the mined seam and do not affect the significant methane emissions that stem from the coal seams and strata above and below the main mined seam.

Warrior Basin. The underground coal mines in the Warrior Basin are well documented as being gassy. The mined coal seam and the adjacent coal seams may contain over 3 billion cubic feet of methane gas in place per each longwall panel, most of which would be emitted during subsequent mining operations.[62] Because of this, many of the underground mines in the Warrior Basin have adopted some form of methane drainage or degasification to supplement the mine ventilation system. Also, because the methane produced by these degasification systems is often of pipeline quality, two mine operators in the Warrior Basin are already collecting and selling this methane as natural gas. A ready market exists for coalbed gas in this basin at wellhead prices of $1.50 to $2.00 per Mcf.

The evaluation of the four methane control techniques indicated that from 18 to 60 percent of the methane that would otherwise be vented during the mining process could be collected and utilized as natural gas (Exhibit 4-6 and Appendix Exhibits C-1 to C-9). In addition, under near-term natural gas market conditions ($2.00 per Mcf wellhead sales price for methane), these techniques can provide a net profit for the mining company.

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[62] Dixon, C.A., 1989.

EXHIBIT 4-6

ECONOMIC ANALYSIS OF THREE DEGASIFICATON SYSTEMS IN THE WARRIOR BASIN

Degasification Method	Methane Recovery	Net Present Value Profit (loss), $/Mcf $0/Mcf**	$2/Mcf**	$3/Mcf**
Vertical wells (10 year production)*	59.8%	(0.71)	0.64	1.32
Vertical wells (5 year production) and gob wells*	59.1%	(0.47)	0.64	1.19
Gob wells*	48.1%	(1.05)	0.95	1.95

* Four wells per longwall panel.
** Assumed gas selling price.

Vertical wells (including those that are later converted to gob wells) are the optimum technique for reducing methane emissions from mining operations in the Warrior Basin. In addition, this analysis also indicates that under current gas market conditions in the basin, the recovery and sale of the methane (if maintained at pipeline quality) would result in a positive net present value profit, thus benefiting the mining operation. Because of the economic attractiveness of degasification practices (along with the positive impact on mining operations), selected mining operations in the Warrior Basin are already recovering and selling methane that would otherwise be vented.

Northern Appalachian Basin. The Northern Appalachian Basin is one of the major coal producing areas of the United States. While large quantities of methane are emitted from the underground mining operations, the amount of methane emitted per ton of coal mined is less than that for the Warrior Basin. This is because the coal seams are shallower and contain less methane, with a typical longwall panel containing less than 1 billion cubic feet of methane. However, some mines must still rely on degasification systems to supplement the ventilation systems. Although a substantial quantity of methane is recovery by these systems, no mines have yet to sell the recovered methane due to difficulty in maintaining pipeline quality, limited economic benefit, restrictive natural gas and environmental regulations, and methane ownership issues.

The evaluation of four methane control techniques indicated that from 16 to 62 percent of the methane can be recovered (Exhibit 4-7 and Appendix Exhibits C-10 to C-18). Although none of this produced methane is currently being recovered and sold in the Northern Appalachian Basin, the analysis indicates that some of the methane recovery techniques could be financially attractive under near-term natural gas market conditions. However, the quality, regulatory, and legal barriers to the capture and sale of this gas must be overcome before mining operations will undertake projects to recover and sell pipeline quality gas.

EXHIBIT 4-7

ECONOMIC ANALYSIS OF THREE DEGASIFICATION SYSTEMS IN THE NORTHERN APPALACHIAN BASIN

Degasification Method	Methane Recovery	Net Present Value Profit (loss), $/Mcf $0/Mcf***	$2/Mcf***	$3/Mcf***
Vertical wells (5 year production) and gob wells*	62.4%	(1.36)	(0.19)	0.39
Vertical wells (5 year production) and gob wells**	48.8%	(0.64)	0.49	1.05
Gob wells*	44.1 %	(1.56)	0.44	1.44

* Four wells per longwall panel.
** Two wells per longwall panel.
*** Assumed gas selling price.

The combination degasification system of using vertical wells that are later converted to gob wells is technically most efficient for reducing methane emissions in the coal mines of the Northern Appalachian Basin. However, unless this methane is recovered and sold, the net present value of such projects are negative. Use of less densely drilled wells such as 2 vertical/2 gob wells, or only gob wells can lead to efficient methane capture and reduced costs to the coal operation. Ultimately, degasification systems should be selected to maximize mine safety and methane recovery.

In summary, this analysis indicates that current degasification practices, especially those that utilize vertical wells drilled in advance of mining, can effectively recover methane that would otherwise be vented in to the atmosphere by coal mining in the two areas studied. Under certain conditions the produced methane can be sold profitably into the natural gas market by the mining operator, as in the Warrior Basin. The economic attractiveness of methane recovery and utilization depends on site-specific geologic, reservoir, and economic conditions. The development of additional projects to produce and sell pipeline quality gas will also require the resolution of institutional, regulatory, legal, and other barriers. If these additional problems are resolved, however, this analysis indicates that the recovery of methane could be economic.

Other Benefits

Additional economic benefits, not addressed in this specific study, can accrue to a mine operator from a mine degasification program. These benefits, while difficult to quantify, may include improved safety for miners resulting from lower volumes of methane emitted into the mine workings, lower ventilation costs, and improved coal production efficiency. One estimate from a mine in the Warrior basin of Alabama indicated that without an active degasification program, the mine would have required three additional ventilation shafts (at a cost of $15 million dollars) and would have had to increase fan volume (at a cost of $250,000 per month).[63]

[63] Dixon, C.A., 1989.

Uncertainties in Methodology

As discussed earlier, the sale of Type 3 methane produced by degasification systems into natural gas pipelines in the United States is one option for the utilization of methane recovered during coal mining. The economic evaluation of this utilization option for the two study areas was based on certain technical and economic assumptions. Some of the major uncertainties in these assumptions and their impact on the evaluation are presented below:

1. **Selection of Underground Mining Scenarios.** The two mining scenarios selected are representative of specific areas within the Warrior and Northern Appalachian Basins, which have significant underground mining activity. However, the specific geologic, reservoir, and mining conditions selected for the study are not representative of any specific mine nor are they representative of the basin as a whole. They were selected to represent conditions that can be found in both basins and therefore provide a first estimate of the potential for methane emission reduction technology. To accurately assess the overall potential for methane emisison reduction, a site-specific assessment of each mining operation would be required.

2. **Selection of Degasification Techniques.** The degasification techniques selected for analysis represent those most commonly used in the United States. However, the actual application of a system to a particular mining operation is not standard, but rather is site-specific to the mining and geologic/reservoir conditions at the mine. For example, the number of wells drilled, the spacing of the wells, and the length of time the wells are in operation are all unique to each mining operation. The studied systems, with their combination of wells, represent only some of the options available to mine operators. In addition, the ability of a mine to specifically plan a degasification system many years in advance is often difficult, due to changing economic, mining, and regulatory conditions.

3. **Modeling of Methane Production.** Estimating the methane production of the various degasification systems was accomplished using a finite difference, numerical production simulator, **COMET PC 3-D**, developed by ICF Resources under contract to the Gas Research Institute. This simulator accurately estimates the production of the various coalbed methane wells types, based on the geologic and reservoir data describing the coal seam and the

engineering data describing the well. As with any numerical simulator, the more reliable the input data, the better the quality of the resulting output.

4. Economic Analysis. The economic analysis assumed capital and operating costs for the various degasification systems and the subsequent utilization potential for the produced methane. The unique conditions of each mining operation preclude the use of the results as being representative of all operations. Rather, the results are indicative of the scenarios studied and provide a basis for determining the relative economics of other methane control techniques.

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Appendices

Appendix A

International Workshop On Methane Emissions From Natural Gas Systems, Coal Mining And Waste Management Systems

April 9-13, 1990
Washington, D.C.

Workshop Findings for Coal Mining

Appendix A

International Workshop On Methane Emissions From Natural Gas Systems, Coal Mining And Waste Management Systems

Workshop Findings for Coal Mining

Emissions Estimates

1.1 Recent global studies of methane emissions from coal mining provide "order of magnitude" estimates and identify those countries with the largest potential opportunities for methane recovery. There are currently many uncertainties about the absolute levels of emissions from this source, however, and about the contributions of various countries to this total.

1.2 Coal mining activities are an important source of methane emissions on a global scale. Current estimates generally suggest that coal mining activities emit about 30-50 million metric tons, although some estimates are as low as 20 million metric tons and others are as high as 60 million metric tons. These emissions are roughly 7 percent of global methane emissions and approximately 10 percent of global anthropogenic methane emissions. However, since both the current estimates and the methodologies which support them include many uncertainties, more research is necessary to refine these estimates.

1.3 To meet the energy requirements associated with increased population and additional development, coal production will likely increase from its current level of about 5 billion tons. If coal production grows at the rate forecast by the International Energy Agency, production levels could exceed 6 billion tons by 2000. In many countries, this increase in production will likely be accompanied by an increase in the proportion of coal mined in underground mines and the depth of these mines. This implies that methane emissions from coal mining could increase by more than 25 percent over the next decade in many countries.

Steps to Improve Emission Estimates

2.1 More research is necessary to refine estimates of methane emissions from coal mining activities.

- One of the most important goals of future research will be to improve the methane emission factors that relate the methane content of the mined coal to the amount of methane emitted from the mine. Among the variables that should be investigated are: depth and rank of coal, geologic and erosional conditions, mine type (underground or surface), mining method (room and pillar or longwall), and age of mine.

- Different models should be developed to approximate emissions in different mining environments and in different coal basins and/or countries.

2.2 These estimates should be further refined by pursuing other research areas, including: (1) improving the instrumentation and techniques used in measuring methane emissions and in-situ gas content; (2) improving data quality (i.e., by collecting better data on methane emissions through ventilation air and degasification systems; (3) improving models for predicting emissions; (4) assessing the relationship between mining practices and emissions; (5) refining estimates of methane emissions from surface mining activities; and (6) investigating emission levels from abandoned mines.

2.3 The methodology used in future studies of methane emissions from coal mining should be clearly documented so that it can be verified by independent analysis. Further, attempts should be made to standardize methane emission measurement methods and estimation techniques to ensure that studies conducted by different researchers are comparable. To this end, consideration should be given to establishing a collaborative international data base on coal and mining characteristics and methane emissions to facilitate the development of global emission estimates.

2.4 To the extent financial resources are limited, future work should focus on those countries where opportunities for recovering methane from coal mining are likely to be large. These countries can be identified based on the "order of magnitude" emission estimates in preliminary studies and based on industry information about the relative gassiness of various coal mines.

2.5 Methane emissions during coal utilization should also be assessed and opportunities for reducing these emissions explored as appropriate. While methane emissions from large utility and industrial coal-fired boilers are low (perhaps less than 10 ppm), it appears that emissions from domestic coal combustion processes could be significant (perhaps on the order of 10-100 ppm).

Technical Potential for Reducing Emissions

3.1 Degasification technologies are used successfully in many countries to maintain mine safety and enhance productivity in mines with high methane emission levels. The benefits of using these technologies include increased safety, reduced downtime, and reduced ventilation costs and capacity requirements.

3.2 Current recovery operations at some mines in the United States and other countries have reduced methane emissions to the atmosphere associated with mining operations by 30-40 percent. The effectiveness of degasification operations at these and other mines must be assessed on a site-specific basis and will depend on many factors, including the methane content of the coal and surrounding strata, the magnitude of the methane emissions, the type and age of the mine, the time available for degasification, and geologic conditions at the site. At some mines with high methane emissions, degasification systems might be able to recover higher levels of methane, while at other mines the recovery potential will not exist at all.

3.3 Most current degasification programs are not being undertaken because of the methane recovery potential, but instead are essential to maintain mine safety. Thus, the current experience with methane recovery might represent economically attractive recovery levels, as opposed to the recovery levels that could be technically achieved.

3.4 Additional benefits result from utilization of the recovered methane. These benefits can include revenue or fuel cost savings from production of the gas and reduced methane emissions to the atmosphere.

3.5 Strategies for using recovered methane should seek to minimize methane emissions to the atmosphere. Many technologies are available to use methane recovered during coal mining. Choices among these technologies depend on methane production rates, gas quality, local energy markets and other factors.

3.6 In developing opportunities for using recovered methane, the safety of mining operations cannot be compromised.

3.7 Many of the opportunities to make additional reductions are not justified on the basis of current mining needs, gas market conditions and investment considerations. Additional reductions may be justified on an environmental basis, however, and the environmental benefits of additional recovery should be examined further. If the value of reducing methane is incorporated into economic assessments (i.e., through the provision of subsidies or low-interest loans) the amount of economically attractive degasification would significantly increase.

3.8 Additional research and government funding is necessary to fully develop the potential for using recovered methane. Work in the following areas is required:

- Technologies that use medium-quality gas and small amounts of gas (from small mines) should be given high priority in future research.

- The recovery and use of methane from ventilation air can potentially be an important source of methane reductions in the future, as appropriate technologies are developed and demonstrated.

- Research is necessary on the optimal integration of utilization technologies and mining operations in a manner that ensures mine safety and maximizes gas recovery and use.

- The interrelationship between coal mining, degasification, and methane utilization should be explored.
- Innovative ways of coupling mining operations with methane utilization options should be developed and implemented.
- Future efforts should emphasize assessing recovery potential, identifying candidate sites and developing demonstration projects.

Policy Options for Reducing Emissions

4.1 Barriers to methane recovery and use -- such as gas ownership, reasonable terms of gas or electricity purchase, and competing environmental goals--should be identified in various countries. Industry, government and environmental groups should work together to remove barriers and to encourage the economic recovery and use of methane from coal mining.

4.2 Government or other financial incentives that recognize the environmental value of limiting methane emissions could greatly increase the level of methane recovered and utilized by mining and other companies.

4.3 Financing will be needed to implement methane recovery systems in developing and Eastern European nations, even for profitable projects.

4.4 International financing organizations should examine energy and environmental policies and should consider the economic costs and benefits of mine degasification and methane utilization, the environmental benefits of using gas instead of venting it, and the opportunities for technology transfer, feasibility studies, and demonstration projects.

Appendix B

International Workshop On Methane Emissions From Natural Gas Systems, Coal Mining And Waste Management Systems

April 9-13, 1990
Washington, D.C.

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Appendix B

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Appendix C

Economic Evaluation of a Methane Control Technique - Detailed Analysis

Appendix C

Economic Evaluation of a Methane Control Technique - Detailed Analysis

As discussed in the second section of Chapter IV of this report, the economic analysis of a coalbed methane utilization process must incorporate the technical capability of the process with the financial costs/benefits of the process. This appendix details the results of the economic analysis of the selected methane utilization option - the sale of the methane produced by degasification systems into natural gas pipelines - for two coal mining areas in the United States.

Warrior Basin

1) Pre-Drainage Using Vertical Wells Completed in All Coal Seams - This methane drainage technique consists of installing 1 to 4 vertical wells drilled from the surface into the longwall panel to pre-drain the methane. Generally, the vertical wells would be completed in all coal seams encountered by the well, including the main seam and the over or underlying coals. Methane recovery efficiencies increase with the number of wells used per panel and with the length of time these wells produce. The ICF Resources analysis shows that methane recovery could vary from 8.7 percent of the methane gas in place (GIP) (1 well per panel, 5 years of production) to nearly 60 percent of GIP (4 wells per panel, 10 years of production), Exhibit C-1. The large scale methane drainage project at Oak Grove, Alabama, operated for twelve years at 25 acres per well spacing, and recovered about 70% of GIP (31 million cubic meters).[64]

The profits realized by a mining company employing the vertical well technique varies depending on the selling price for the gas, the number of wells used, and the length of time the project is operated. Where the degasification wells are drilled five years in advance of mining, using four vertical wells per panel, the operator could capture 48 percent of the in-place methane and achieve a NPV profit of $0.59 per ton coal mined, Exhibit C-2. If the degasification program

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64 Diamond, W.P, Bodden, W.R., Zuber, M.D., and Schraufnagel, R.A., 1989.

EXHIBIT C-1

SUMMARY OF COALBED METHANE PRODUCTION PRE-DRAINAGE USING VERTICAL WELLS COMPLETED IN ALL COAL SEAMS, WARRIOR BASIN

		Cumulative Methane Production		NPV Profit (Loss)					
				$0/Mcf**		$2/Mcf**		$3/Mcf**	
Number of Wells	Well Spacing (Acres/Well)	(MMcf)	(% GIP)*	$/Ton	$/Mcf	$/Ton	$/Mcf	$/Ton	$/Mcf
Vertical Wells Produced 5 Years									
1	95.5	240	8.7	(0.18)	(1.13)	0.05	0.29	0.16	1.00
2	47.8	746	27.1	(0.38)	(0.76)	0.31	0.63	0.66	1.32
4	23.9	1,324	48.1	(0.72)	(0.81)	0.59	0.66	1.24	1.40
Vertical Wells Produced for 10 Years									
1	95.5	471	17.1	(0.21)	(0.65)	0.15	0.48	0.33	1.05
2	47.8	1,128	41.0	(0.41)	(0.54)	0.51	0.67	0.97	1.28
4	23.9	1,646	59.8	(0.79)	(0.71)	0.71	0.64	1.45	1.32

* Total Gas in Place (GIP) for 95.5-Acre Mine Block is 2,751 MMcf.
** Assumed gas selling price.

is planned well in advance of mining (10 years), is intensely developed (4 wells per panel), and the produced methane can be sold at the mine for $2.00 per Mcf, the operator could realize a NPV profit of $0.71 per ton of coal mined while also capturing nearly 60 percent of the methane in-place in all coal seams, Exhibit C-3. At higher gas prices of $3.00 per Mcf, the NPV profit could reach $1.45 per ton of coal mined.

2) Drainage Using Vertical Gob Wells During Mining - Vertical gob wells capture the methane present in the fractured gob area behind an advancing longwall face. Because of this, recovery efficiencies are high and increase as the number of gob wells used increases. In the Warrior Basin, it is estimated one gob well could capture 32 percent of the GIP while four gob wells could capture up to 48 percent of the GIP, Exhibit C-4.

Because gob wells produce large volumes of methane in a very short period of time (1 year), the profits obtained from the sale of the methane can be substantial. The NPV profit for this methane control technique is estimated to range from $0.71 to $0.84 per ton of coal mined at a $2.00 per Mcf wellhead gas sales price, Exhibit C-5.

3) Pre-Drainage Using In-Mine Horizontal Boreholes - This methane drainage technique is one of the most widely used in the mining industry, particularly in situations where methane emissions exceed the capacity of the mine ventilation system. Most often, horizontal boreholes are used for short-term methane emissions relief during mining. However, because methane drainage only occurs from the mined coal seam, the recovery efficiencies of this technique would be low, ranging from 10 to 18 percent, Exhibit C-6.

Because of the smaller quantities of methane produced, profits from the use of horizontal boreholes would likely be lower than for the other degasification techniques, ranging from $0.21 to $0.35 per ton of mined coal, at $2.00 per Mcf gas sales price, Exhibit C-7.

4) Pre-Drainage Using Vertical Wells and Drainage Using Gob Wells - Efficient recovery of methane could be achieved in a short period of time through the use of a combined vertical/gob well degasification system. This involves drilling vertical wells in advance of mining to drain the methane from the coal seam to be mined and then converting these wells into gob

EXHIBIT C-4

SUMMARY OF COALBED METHANE PRODUCTION DRAINAGE USING VERTICAL GOB WELLS DURING MINING, WARRIOR BASIN

Number of Wells	Well Spacing (Acres/Well)	Cumulative Methane Production (MMcf)	Cumulative Methane Production (% GIP)*	NPV Profit (Loss) $0/Mcf** $/Ton	NPV Profit (Loss) $0/Mcf** $/Mcf	NPV Profit (Loss) $2/Mcf** $/Ton	NPV Profit (Loss) $2/Mcf** $/Mcf	NPV Profit (Loss) $3/Mcf** $/Ton	NPV Profit (Loss) $3/Mcf** $/Mcf
1	95.5	886	32.2	(0.47)	(0.80)	0.71	1.20	1.30	2.20
2	47.8	1,117	40.6	(0.66)	(0.88)	0.83	1.12	1.58	2.12
4	23.9	1,323	48.1	(0.93)	(1.05)	0.84	0.95	1.73	1.95

* Total Gas In Place for 95.5-Acre Mine Block is 2,751 MMcf.
** Assumed gas selling price.

EXHIBIT C-6

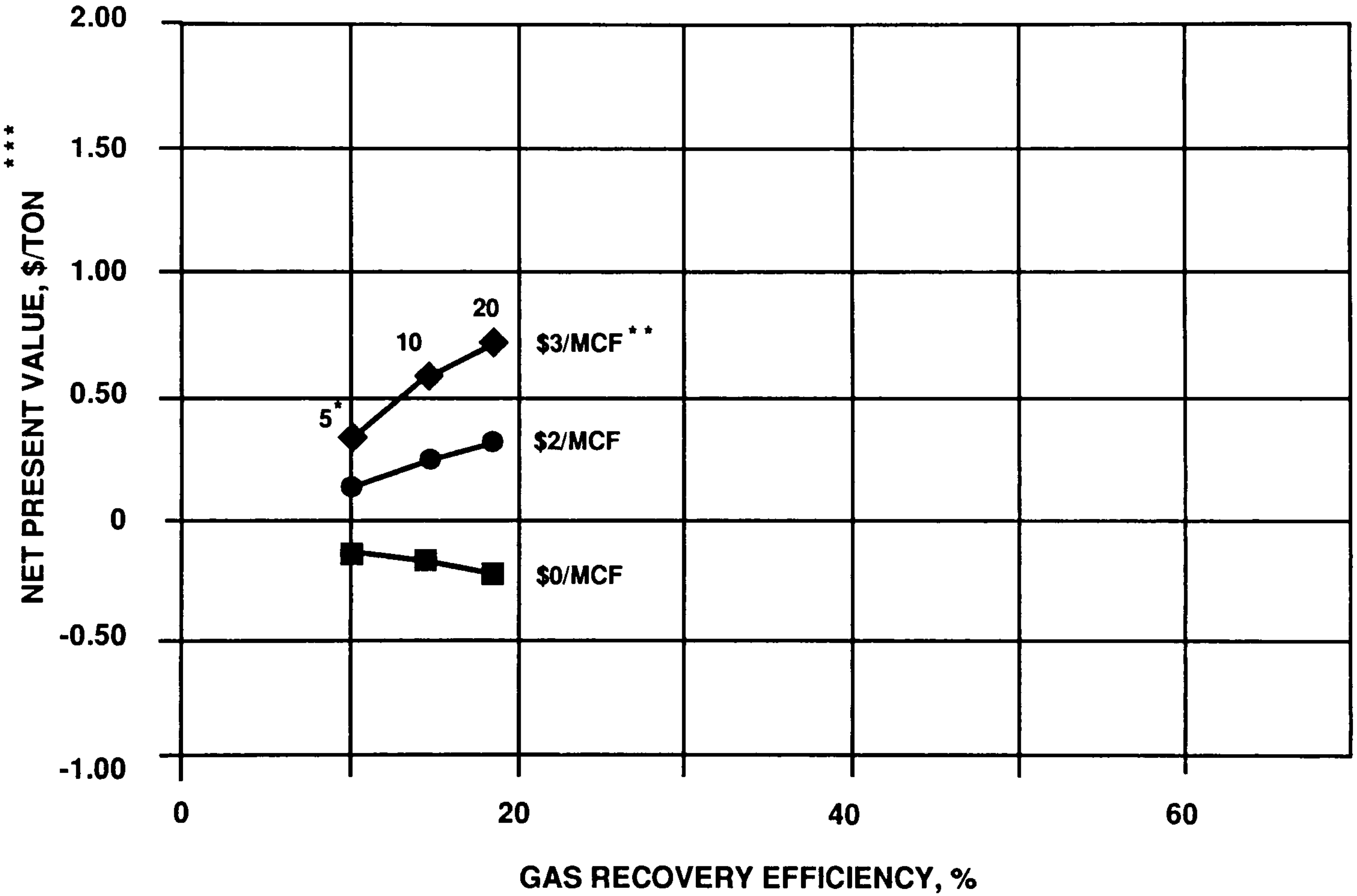
SUMMARY OF COALBED METHANE PRODUCTION PRE-DRAINAGE USING IN-MINE HORIZONTAL BOREHOLES COMPLETED IN THE MARY LEE COAL SEAM, WARRIOR BASIN

		Cumulative Methane Production		NPV Profit (Loss)					
				$0/Mcf**		$2/Mcf**		$3/Mcf**	
Number of Wells	Well Spacing (Acres/Well)	(MMcf)	(% GIP)*	$/Ton	$/Mcf	$/Ton	$/Mcf	$/Ton	$/Mcf
5	19.1	270	9.8	(0.15)	(0.86)	0.21	1.14	0.39	2.14
10	9.6	397	14.4	(0.23)	(0.88)	0.30	1.12	0.56	2.12
20	4.8	506	18.4	(0.33)	(0.97)	0.35	1.03	0.69	2.03

* Total Gas In Place (GIP) for 95.5-Acre Mine Block is 2,751 MMcf.
** Assumed gas selling price.

EXHIBIT C-7

ECONOMIC BENEFITS OF USING HORIZONTAL BOREHOLES FOR METHANE RECOVERY IN THE WARRIOR BASIN



* Number of wells per panel

** Gas sales price at the wellhead

*** Net Present Value does not include potential benefits to the mining operation (reduced ventilation requirements, production increases, etc.) nor investment cost savings realized from already installed methane control systems.

Prepared by: ICF Resources, 1990

F07031-3

wells to drain the methane in the fractured gob area. Assuming 5 years of pre-drainage prior to converting the vertical wells to gob wells, from 34 to 59 percent of the methane could be captured, Exhibit C-8. The economics of this combined vertical/gob well degasification system could be attractive. At a $2.00 per Mcf sales price, the NPV profit could range from $0.51 to $0.69 per ton of mined coal depending on the number of vertical and gob wells drilled, Exhibit C-9.

EXHIBIT C-8

SUMMARY OF COALBED METHANE PRODUCTION PRE-DRAINAGE USING VERTICAL WELLS COMPLETED IN THE MARY LEE COAL SEAM AND DRAINAGE USING VERTICAL GOB WELLS DURING MINING, WARRIOR BASIN

Number of Wells*	Well Spacing (Acres/Well)	Cumulative Methane Production (MMcf)	Cumulative Methane Production (% GIP)**	NPV Profit (Loss) $0/Mcf*** $/Ton	$0/Mcf*** $/Mcf	$2/Mcf*** $/Ton	$2/Mcf*** $/Mcf	$3/Mcf*** $/Ton	$3/Mcf*** $/Mcf
1	1	933	33.9	(0.14)	(0.23)	0.51	0.82	0.84	1.34
2	2	1,275	46.4	(0.32)	(0.37)	0.59	0.69	1.05	1.23
4	4	1,627	59.1	(0.51)	(0.47)	0.69	0.64	1.29	1.19

* Vertical Well Production for 5 years.

** Total Gas in Place (GIP) for 95.5-Acre Mine Block is 2,751 MMcf.

*** Assumed gas selling price.

Northern Appalachian Basin

1) Pre-Drainage Using Vertical Wells Completed in All Coal Seams - Because the reservoir conditions of the Northern Appalachian coal seams are somewhat less favorable to pre-drainage using vertical wells, a maximum methane recovery of 9 to 40 percent was estimated depending on the number of wells drilled and the length of time these wells are produced, Exhibit C-10.

If market and regulatory conditions become favorable in the near-term in the Northern Appalachian Basin, the $2/Mcf line on the following exhibits is the appropriate baseline. However, if the mining company produces methane only for emissions relief in the mine and does not sell the gas, as is the current situation in the basin, then the operation would be an added cost ($0/Mcf line). The technically most efficient, although economically most costly option, is a 10-year pre-drainage program using 4 wells per panel which could lead to recovery of 40 percent of GIP. This program is estimated to cost, on an NPV basis, $0.30 per ton of coal mined even with a wellhead gas price of $2 per Mcf. This cost would increase to $0.67 per ton of coal mined with no sale of the produced gas, Exhibits C-11 and C-12.

2) Drainage Using Vertical Gob Wells During Mining - Gob wells are an effective methane drainage practice for the Northern Appalachian Basin, as evidenced by estimated methane recoveries of 28 to 44 percent of GIP, Exhibit C-13.

Because of projected lower installation and operating costs, methane recovery with gob wells in the Northern Appalachian Basin could be a moderate cost methane control technique, when the produced methane is not sold. The NPV costs of using 1 to 4 gob wells would be $0.18 to $0.45 per ton of mined coal, Exhibit C-14. If a market exists for the gas (at $2 per Mcf), this technique becomes economically attractive with a projected NPV profit of $0.13 to $0.19 per ton of coal mined.

EXHIBIT C-10

SUMMARY OF COALBED METHANE PRODUCTION PRE-DRAINAGE USING VERTICAL WELLS COMPLETED IN ALL COAL SEAMS, NORTHERN APPALACHIAN BASIN

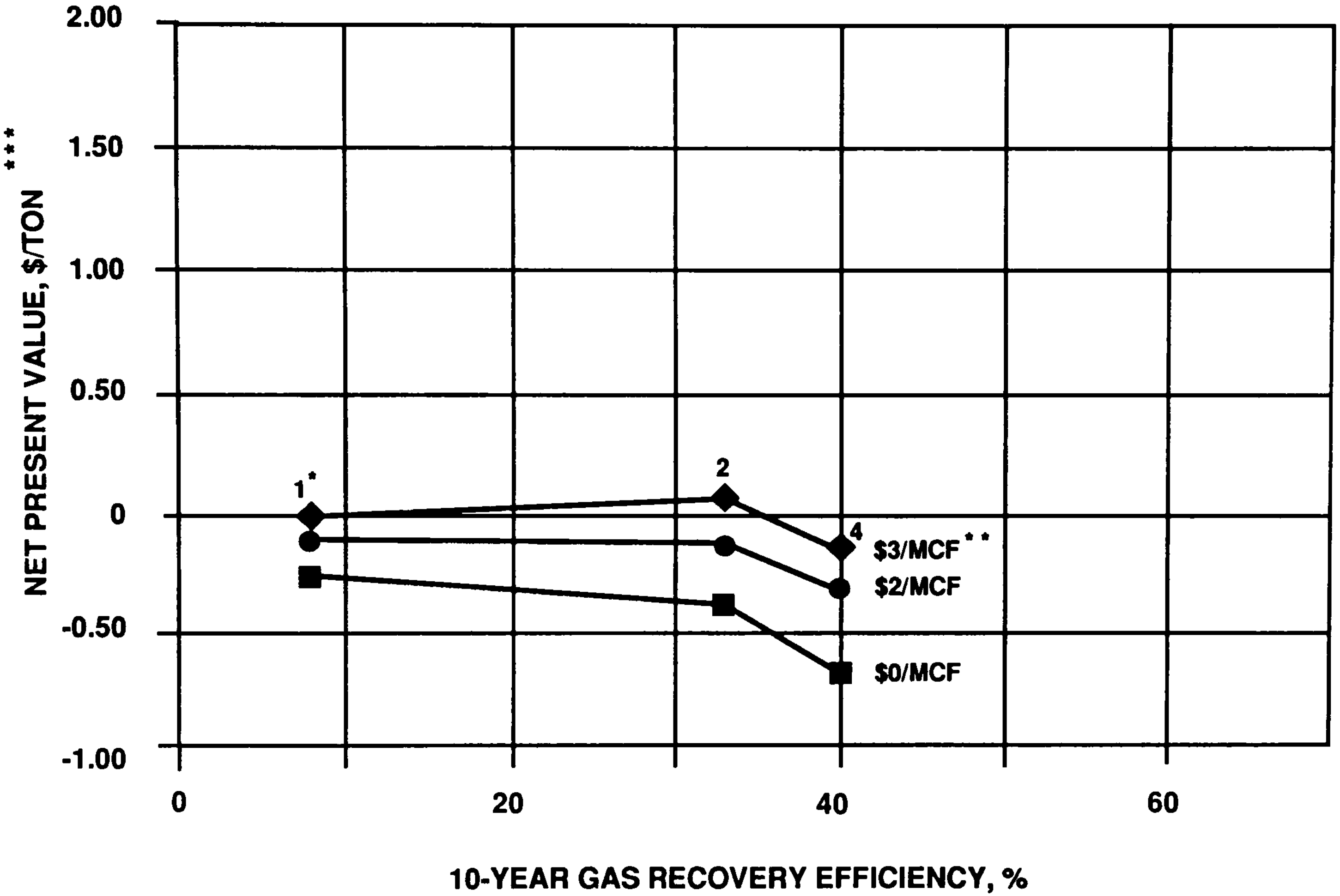
Number of Wells	Well Spacing (Acres/Well)	Cumulative Methane Production (MMcf)	Cumulative Methane Production (% GIP)*	NPV Profit (Loss) $0/Mcf** $/Ton	NPV Profit (Loss) $0/Mcf** $/Mcf	NPV Profit (Loss) $2/Mcf** $/Ton	NPV Profit (Loss) $2/Mcf** $/Mcf	NPV Profit (Loss) $3/Mcf** $/Ton	NPV Profit (Loss) $3/Mcf** $/Mcf
Vertical Wells Produced 5 Years									
1	95.5	78	8.7	(0.16)	(2.83)	(0.08)	(1.41)	(0.04)	(0.71)
2	47.8	205	22.9	(0.32)	(2.15)	(0.11)	(0.75)	(0.01)	(0.06)
4	23.9	321	35.9	(0.62)	(2.66)	(0.28)	(1.18)	(0.10)	(0.44)
Vertical Wells Produced for 10 Years									
1	95.5	141	15.7	(0.17)	(1.68)	(0.05)	(0.51)	0.01	0.07
2	47.8	296	33.1	(0.34)	(1.59)	(0.07)	(0.35)	0.06	0.27
4	23.9	355	39.7	(0.67)	(2.60)	(0.30)	(1.17)	(0.12)	(0.46)

* Total Gas in Place (GIP) for 95.5-Acre Mine Block is 895 MMcf.

** Assumed gas selling price.

EXHIBIT C-12

ECONOMIC BENEFITS OF USING VERTICAL WELLS FOR METHANE RECOVERY IN THE NORTHERN APPALACHIAN BASIN



Prepared by: ICF Resources, 1990

* Number of wells per panel

** Gas sales price at the wellhead

*** Net Present Value does not include potential benefits to the mining operation (reduced ventilation requirements, production increases, etc.) nor investment cost savings realized from already installed methane control systems.

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EXHIBIT C-13

SUMMARY OF COALBED METHANE PRODUCTION DRAINAGE USING VERTICAL GOB WELLS DURING MINING, NORTHERN APPALACHIAN BASIN

Number of Wells	Well Spacing (Acres/Well)	Cumulative Methane Production (MMcf)	Cumulative Methane Production (% GIP)*	NPV Profit (Loss) $0/Mcf** $/Ton	NPV Profit (Loss) $0/Mcf** $/Mcf	NPV Profit (Loss) $2/Mcf** $/Ton	NPV Profit (Loss) $2/Mcf** $/Mcf	NPV Profit (Loss) $3/Mcf** $/Ton	NPV Profit (Loss) $3/Mcf** $/Mcf
1	95.5	247	27.6	(0.18)	(1.01)	0.18	0.99	0.35	1.99
2	47.8	322	36.0	(0.28)	(1.21)	0.19	0.79	0.42	1.79
4	23.9	395	44.1	(0.45)	(1.56)	0.13	0.44	0.41	1.44

* Total Gas In Place (GIP) for 95.5-Acre Mine Block is 895 MMcf.
** Assumed gas selling price.

3) <u>Pre-Drainage Using In-Mine Horizontal Boreholes</u> - For the Northern Appalachian Basin, recovery efficiencies associated with horizontal boreholes range from 16 to 20 percent of GIP depending on the number of boreholes drilled into a panel, Exhibit C-15.

Use of horizontal boreholes in the Northern Appalachian Basin, while a relatively inefficient technique for methane capture, would be the lowest cost option. The projected NPV costs projected would be $0.12 to $0.19 per ton of coal mined, Exhibit C-16. Horizontal boreholes could produce a net profit of $0.07 to $0.11 per ton of mined coal if the gas could be sold for $2 per Mcf at the mine mouth.

4) <u>Pre-Drainage Using Vertical Wells and Drainage Using Gob Wells</u> - As was the case for the Warrior Basin, the combined vertical/gob well degasification practice in the Northern Appalachian Basin is a highly efficient short term technique for recovering methane from coal mines. From 33 to 62 percent of the methane that would otherwise be emitted could be captured depending on the number of vertical and gob wells used, as shown in Exhibit C-17.

This analysis shows that a 2 vertical/2 gob well system would be the relatively low cost yet high recovery efficiency technique providing a projected methane recovery of nearly 50 percent at a cost of only $0.20 per ton of coal mined (no gas sold), Exhibit C-18. This is also a profitable technique, if the gas could be sold at $2/Mcf at the wellhead, with a potential profit of $0.15 per ton of coal mined.

EXHIBIT C-15

SUMMARY OF COALBED METHANE PRODUCTION
PRE-DRAINAGE USING IN-MINE HORIZONTAL BOREHOLES
COMPLETED IN THE PITTSBURGH COAL SEAM, NORTHERN APPALACHIAN BASIN

		Cumulative Methane Production		NPV Profit (Loss)					
				$0/Mcf**		$2/Mcf**		$3/Mcf**	
Number of Wells	Well Spacing (Acres/Well)	(MMcf)	(% GIP)*	$/Ton	$/Mcf	$/Ton	$/Mcf	$/Ton	$/Mcf
5	19.1	147	16.4	(0.12)	(0.96)	0.11	1.04	0.22	2.04
10	9.6	170	19.0	(0.14)	(1.11)	0.11	0.89	0.23	1.89
20	4.8	179	20.0	(0.19)	(1.44)	0.07	0.56	0.20	1.56

* Total Gas In Place (GIP) for 95.5-Acre Mine Block is 895 MMcf.
** Assumed gas selling price.

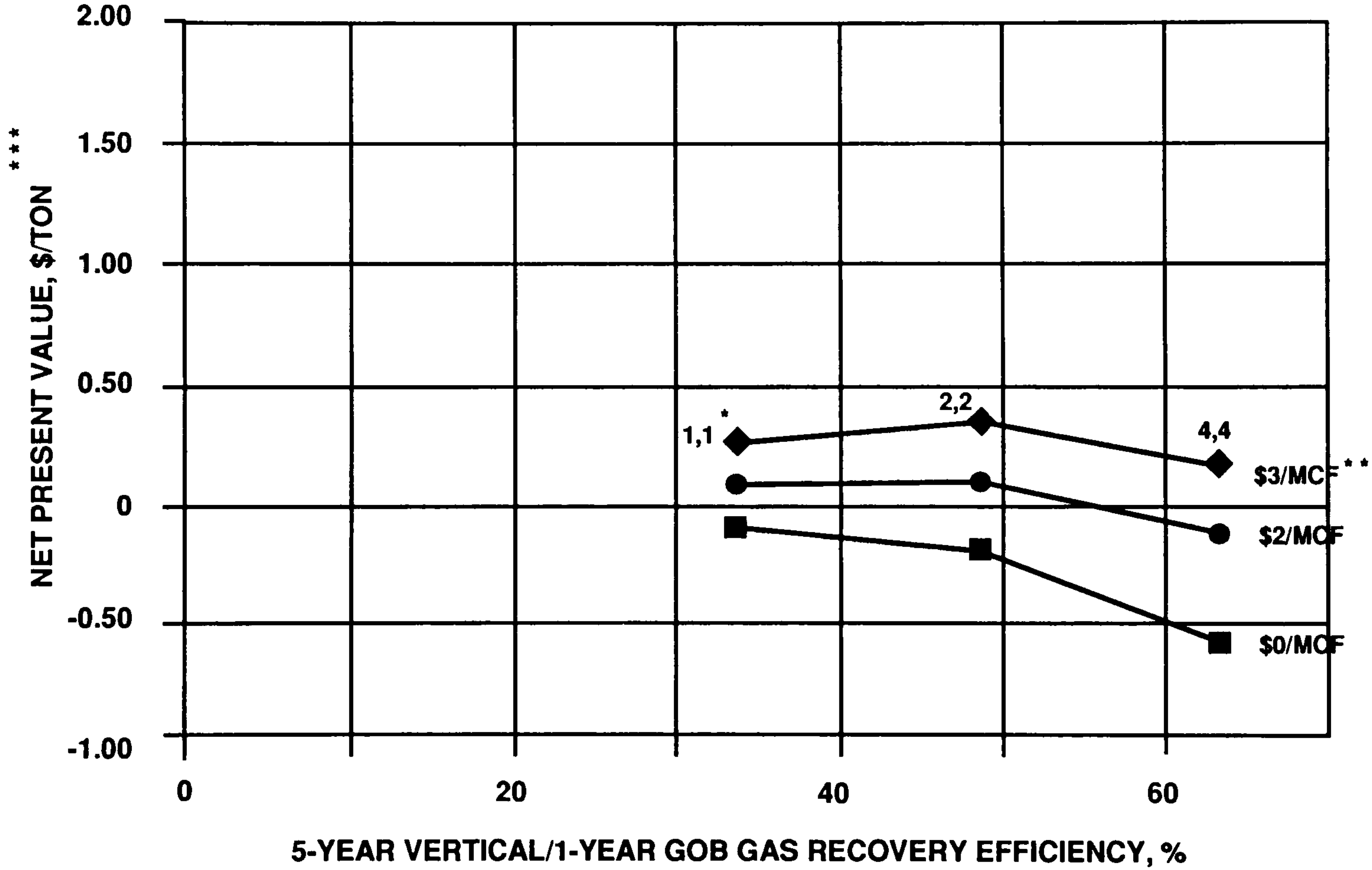
EXHIBIT C-17

SUMMARY OF COALBED METHANE PRODUCTION PRE-DRAINAGE USING VERTICAL WELLS COMPLETED IN THE PITTSBURGH COAL SEAM AND DRAINAGE USING VERTICAL GOB WELLS DURING MINING, NORTHERN APPALACHIAN BASIN

Number of Wells*	Well Spacing (Acres/Well)	Cumulative Methane Production (MMcf)	Cumulative Methane Production (% GIP)**	NPV Profit (Loss) $0/Mcf*** $/Ton	NPV Profit (Loss) $0/Mcf*** $/Mcf	NPV Profit (Loss) $2/Mcf*** $/Ton	NPV Profit (Loss) $2/Mcf*** $/Mcf	NPV Profit (Loss) $3/Mcf*** $/Ton	NPV Profit (Loss) $3/Mcf*** $/Mcf
1	1	291	32.5	(0.09)	(0.44)	0.14	0.64	0.25	1.19
2	2	436	48.8	(0.20)	(0.64)	0.15	0.49	0.33	1.05
4	4	558	62.4	(0.55)	(1.36)	(0.08)	(0.19)	0.16	0.39

* Vertical Well Production for 5 years.
** Total Gas in Place (GIP) for 95.5-Acre Mine Block is 895 MMcf.
*** Assumed gas selling price.

EXHIBIT C-18
ECONOMIC BENEFITS OF USING VERTICAL AND GOB WELLS FOR METHANE RECOVERY IN THE NORTHERN APPALACHIAN BASIN



* Number of wells per panel

** Gas sales price at the wellhead

*** Net Present Value does not include potential benefits to the mining operation (reduced ventilation requirements, production increases, etc.) nor investment cost savings realized from already installed methane control systems.

Prepared by: ICF Resources, 1990

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